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# Numerical simulation of relative permeability modifier effect on oil and water production

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NUMERICAL SIMULATION OF RELATIVE PERMEABILITY MODIFIER EFFECT ON OIL AND WATER PRODUCTION

by

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## ABSTRACT

Excess water production is one of the most prevalent operational problems that oil companies are facing. Polymers and polymer gels have been used widely to control excess water production for mature oilfields. It is well known that polymers/gels can reduce the permeability to water (Krw) much more than that to oil (Kro). This phenomenon is called disproportionate permeability reduction (DPR) and the polymers or gels that exhibit this behavior are called relative permeability modifier (RPM). When RPMs are placed in reservoir, reduced permeability to water can lead to decreased water production, and sometimes increased hydrocarbon production, therefore prolonging the useful life of the reservoir. However, arguments exist about where and when RPM can be used.

Numerical simulation was run to investigate whether RPM can be used to reduce water production and increase oil recovery for two reservoir models: one layer homogeneous formation, two-layer heterogeneous formation with crossflow. Linear flow and five-spot well patterns were considered for the simulation. Results showed that the relative permeability modification with five spot and two layers flow pattern is more effective than linear flow with two layers and one layer. The effective period of DPR treatment is longer if treated in low water cut than in high water cut. DPR can improve oil production and reduce water production during the effective period of a treatment but the final recovery could not be significantly improved even sometimes worse. Results also show that better water control results can be achieved with more gel injection.

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# 1. INTRODUCTION

Almost all oil or gas reservoirs produce water. Since nature does not like vacuums, water usually replaces oil as hydrocarbon reserves decline in the field. In mature oil fields, most of the produced fluid is water, with oil or gas representing a small percent of the total production. Moreover, many reservoirs are submitted to water injection, which provides pressure maintenance and improves sweep efficiency. A continuous increase in water production is thus normal in the lifetime of a field. Water flow paths in the reservoir, especially close to the wellbore, are irregular. They by-pass large hydrocarbon-saturated zones and induce undesirable high water-cut levels. In such situations, "bad" or undesirable water is produced, as opposed to "good" water that is created under normal conditions. Chemically enhanced oil recovery, especially gel treatment, is a crucial process to shut off or reduce excess water production while at the same time increasing the hydrocarbon production rate in mature oil and gas fields.

Robert et al, (2007) explained when treating unfractured and multizoned production wells that are not fully drawn down, the well’s long-term oil-production rate can be increased if the post-treatment drawdown can be increased substantially. Also, treatments that promote short-term (transient) decreased water/oil ratios can, in principle, be applied to many unfractured production wells (that are not totally watered out) in matrix-rock reservoirs.

In this study one- and two-layer reservoirs were considered for a strong permeability modification, treatment which intends to decrease water influx from the high-permeability layer or fingering effect, thus favoring oil production. When the different layers are clearly separated and work over costs are acceptable, a water shutoff treatment aims at sealing off the watered-out layer with strong gels placed by mechanical tools (coil tubing, packers, etc.). Nevertheless, in practice, bullheading is often the only option for the operator due to several problems like poor identification of the different zones surrounding the wellbore, multilayered production, unfavorable completion (gravel pack, slotted liners, etc.) or relative permeability to water more than the relative permeability to oil or to gas. Liang et al. (1995) ” indicated that a method called “disproportionate permeability reduction” (DPR). This unique property is the basis for the use of polymers and gels as water control agents in near-wellbore treatments of production wells, especially when polymer injection has to be bullheaded without mechanical zone isolation to protect the oil zones. High water production in association with crude oil is one of the major production difficulties for the petroleum industry. Coning due to bottom water drive and production from high-permeability watered-out layers during flooding are among the main causes. Water handling and disposal costs often shorten the economic life of a well.

Disposal of produced water is also an environmental concern, especially offshore. The application of relative permeability modifiers is useful in wells where oil/gas-producing zones cannot be isolated, and bullhead treatments are required. In this case, polymers or gelant solutions are mixed at the surface and injected into the reservoir through a production well. Once inside the formation, a gel is formed or the polymer is retained within the rock. The ideal relative permeability modification (RPM) treatment will reduce the effective permeability to water without affecting the oil/gas permeability. As the properties of the flowing fluids remain unchanged before and after treatment, the polymer/gel must cause some modifications in the pore sizes, fluid distribution and flow paths at the pore level, in order for the relative permeabilities to be changed.

Reservoir simulation is a form of numerical modeling which is used to quantify and interpret physical phenomena with the ability to extend these to predict future performance. The process involves dividing the reservoir into a number of discrete units in three dimensions and modeling the progression of reservoir and fluid properties through space and time in a series of discrete steps. The equation solved for each cell and each time step is a combination of the mass conservation and an equation of state. There are several different techniques that can be used to solve the resulting equation.

In this numerical simulation study, four of scenarios were run to examine the effect of polymer and gel treatment on water and oil flow. This study benefits the industry by demonstrating the applicability of polymer gel treatment to reduce the permeability of water flow and detailing numerical simulation methods necessary to extrapolate this work to oil reservoirs. This study also presents an easy-to-follow procedure to assist with the understanding of this RPM-treatment prediction technique as a low cost alternative to a side track or re-drill. Evaluation of water shutoff treatment should not be based on observed water cut reduction, but on added value to operations with respect to water cost saving, oil revenue, or both.

This method will provide a practical method to improve sweep efficiency. The demand for effective and selective chemical water control techniques is at an all-time high, as old fields tend towards maturity and decline. Results of the current work demonstrate that these relative permeability curves were employed to identify conditions where relative permeability modifiers can be used with potential for success.

## 1.1 OBJECTIVE OF THESIS

The objectives of this study are:

- To answer whether DPR can be used in homogenous reservoirs and multiple-layer reservoirs with crossflow through numerical simulation study.
- To when is the best time to implement DPR treatment
- To understand the fundamentals of gel polymer's effect on water and oil flow in rocks.
- To understand the mechanisms of DPR to water and oil in a reservoir scale.
- To provide guidance for maximizing DPR through the selection of gel polymer for different formations.

# 2. REVIEW OF LITERATURE

This section provides the background of one of the major challenges facing the petroleum industry; excessive unwanted water production from hydrocarbon reservoirs is increasing worldwide as more reservoirs are becoming mature. Water production is a serious problem in mature oil and gas fields. By some estimates, it represents the largest single waste stream in the United States. Water handling and disposal costs decrease the economic life of a field. Disposal of produced water also is an environmental concern, both on- and off-shore. To mitigate this problem, scientists and engineers have introduced gel as a plugging agent. A gel plug fractures and thus restricts water from following through these paths, directing it instead into low-permeability areas. Gel is also used to reduce channeling in gas flooding reservoirs (Seright et al. 1995).

## 2.1 ENHANCED OIL RECOVERY POTENTIALS

Fewer new wells are being drilled (Annual DOE Report, 2008, 2009), and fewer large oil reservoirs are presumed to be available. Drilling expenses have increased dramatically, and fewer companies are capable of making investments in such technologies as deeper wells that are necessary to reach target zones. These and other factors have made EOR much more attractive in the United States, Canada, and other countries.

Rising world oil prices have redirected the interest of oil companies around the globe toward improving the availability of recoverable reserves and protecting EOR technology. EOR projects once considered economically risky now seem practical

(Anderson et al. 2006). High prices have also compelled companies to increase their production rates.

Secondary production in many fields is reaching its economic limit, and the focus is shifting to asset development. Tertiary methods have been proven to work (Adams et al.1987; Chang et al. 2006; Jayanti et al. 2002; Bai et al. 2007), and in many reservoirs worldwide a large portion of the original oil in place (OOIP) remains. The potential for EOR worldwide therefore is very high. In recent years, numerous advancements have made these technologies not only more practical, but also economically feasible.

## 2.2 EXCESS WATER PRODUCTION AND ASSOCIATED PROBLEMS

A serious problem in oil-producing reservoirs is water production. On average in the United States, more than seven barrels of water are produced for each barrel of oil. Worldwide, the average is three barrels of water for each barrel of oil. The annual cost of disposing of this water is estimated to be $5-10 billion in the United States and around $40 billion worldwide (Seright et al. 2000). As with most things in nature, fluids flow through the paths of least resistance. In reservoirs, such paths are often determined by the heterogeneous nature of the rock. According to the Department of Energy (DOE), produced water is defined as the water brought up from the hydrocarbon-bearing strata during extraction of oil or gas. It can include formation water, injection water, condensed water, and trace amounts of treatment chemicals.

Produced water is the highest volume waste generated in association with oil and gas production operations. This waste stream is characterized by high volume and low toxicity. Over its life span, a typical oil field is likely to produce at least as much water as oil. In gas fields, the volume of produced water is significantly lower.

Diagnosis and management of water production problems have been objectives of the oil industry almost since its inception because produced water has a major impact on the profitability of an oilfield project. Producing one barrel of water requires as much or more energy as producing the same volume of oil (Eoff et al. 2006). Moreover, water production causes major problems such as sand production, reduced oil production, and tubular corrosion.

Remedies have been elusive. The oil industry has seen many attempts to manage water production. Historically, it has used the most convenient or least expensive methods such as reperforation and cement plugs. Today, some strategies have been implemented to restrict water from entering the well bore. These involve mechanical blocking devices or chemicals that shut off water-bearing channels or fracture within the formation and prevent water from making its way to the well.

## 2.3 METHODS TO REDUCE WATER PRODUCTION

The aim of this research is to present a method to reduce water production by changing RPM using a numerical simulation study. This knowledge could allow improving the oil production and design of products in order to increase the success of well treatments.

Operators have used various mechanical and well construction techniques to block water from entering wells. Seright et al. (2000) offer several examples, including straddle packers, bridge plugs, tubing patches, well bore sand plugs, infill drilling, pattern flow control, and horizontal wells. These techniques have been used for many years, but they do not work well in all applications. Seright recommends that mechanical approaches be used to block casing leaks, flow behind the pipe without flow restrictions, and unfractured wells with barriers to cross flow. However, these approaches may not be effective in solving other types of water production problems.

Seright (2000) summarizes the causes of excess water production. Each of these problems requires a different approach, so a successful treatment of water production problems depends on correct identification of the nature of the problem. Many different materials and methods can be used to assess excess water production problems. Generally, these methods can be categorized as either mechanical or chemical.

Another approach of particular interest here is to shut off water production by chemical injection while allowing continued oil production. The chemicals are introduced deep in the formation where they are unlikely to affect the underground water and will thus have a net beneficial impact.

Most previous research effort has been directed toward testing polymer or gels in cores and sand-packs to improve the understanding of water control. However, the effects of RPM could vary with the polymer/gel system and the particular conditions studied. As a consequence, several theories have been proposed (Liang and Seright, 1997; Zaitoun and Bertin, 1998; Barreau et al., 1999; Dalrymple et al., 2000; Liang and Seright, 2000; Al-Sharji et al., 2001a; Stavland and Nilsson, 2001; Grattoni et al., 2002), but there is a lack of general agreement between researchers on the basic mechanisms and the conditions under which they are applicable.

Polymer retention in a porous medium generally decreases the permeability of water. This phenomenon can be modeled by applying a layer of adsorbed polymer onto the pore walls, which reduces the pore sizes. Zaitoun and Bertin (1998) describe the oil and water relative permeability modification in terms of wall effects resulting from the adsorbed polymer layer. The adsorbed layer thickness can be estimated by modeling the pores of the system as a bundle of capillary tubes, and the reduction in permeability can be used to calculate the thickness of the polymer layer (Zaitoun and Kohler, 1988).

Their interpretation indicated that a multilayer might be formed by mechanical entanglement between the flowing and immobile polymer molecules. Al-Sharji et al. (2001b) performed polymer flow experiments in water-wet micro-models and observed the build-up of polymer in the crevices (along the grain–grain contact), which induced a significant water permeability reduction with little effect in the oil permeability. However, no layers or RPM effects were observed in oil-wet models.

## 2.4 GEL TREATMENT

When gels set up in the cracks, they block most water movement to the well while still allowing oil to flow to the well. Many different types of gels can be used, depending on the specific type of water flow to be targeted. Thomas et al. (2000), Mack et al. (2003), Seright et al. (2001), and Green et al. (2001) discuss the key factors to be considered when designing and conducting a gel treatment. Among the most important considerations are component ingredients, gel properties, and treatment processes.

Green et al. (2001) described a series of gel treatments at four Kansas wells. Each treatment cost $14,000 to $18,000 per well, including polymer and well servicing costs.

Following treatment, the total oil production increased by about 30 barrels per day (bpd), and water production dropped by about 1,000 bpd. Lifting costs associated with the lower fluid volume decreased by about $300/month/well. With less stress on the lifting equipment, well servicing costs also decreased by about $2,400/year/well. Since mid-2000, a total of about 37,500 bbl of oil have been economically recovered, representing about $1.60 per incremental bbl to date, and several years of production are still anticipated. The gel polymer treatments extended the economic life of the wells by at least seven years.

Reynolds et al. (2002) and Mack et al. (2003) suggest the following criteria for selected candidate wells for gel treatment: the wells must be near the end of their economic lives, have significant remaining mobile oil in place, contain a high water to oil ratio, have a high-producing fluid level, have declining oil and flat water production, be associated with active natural water drive, and have a high permeability contrast between oil- and water-saturated rocks.

**2.4.1 Gel Types.** Gel properties depend mainly on the chemical composition of the gel, including polymer concentration and the degree of crosslinking. Gel treatments can be applied by using different types of gels which have different chemical compositions and particle sizes. The two types of gel most commonly used by the oil industry today are in-situ gels and PPGs.

Both in-situ gel and PPGs have the same function of reducing the reservoir heterogeneity and improve the sweep efficiency, but they differ in terms of composition and method of preparation; thus they produce different results. Injection of stable preformed microgels modifies relative permeability and reduces water production. The procedure is an attractive means to minimize the risk of formation plugging and ensure the efficiency of in-depth treatments.

Gel is a crosslinked polymer consisting of several chemical materials including a polymer, a crosslinker and some additives. Polymer gels were first applied in the 1970s when partially hydrolyzed polyacrylamide was used to control conformance in oil reservoirs. Polyacrylamide in its pure state is electrically neutral and comprises a carbon-carbon backbone hung with amide groups. PAMs used in in-situ gel systems are all partially hydrolyzed to carry a negative charge. Therefore, it can form an ionic bonding with multivalent cations.

PPGs are dried crosslinked polyacrylamide powders. They use super absorbent polymers (SAPs) that can absorb over a hundred times their weight in liquids and do not easily release the absorbed fluids under pressure (Bai et al.  2008).

According to Bai et. al (2007), particle gels have great potential for conformance control due to their unique advantages over traditional in-situ gels. PPGs are synthesized prior to formation contact, thus overcoming several drawbacks of in-suite gelation systems, such as uncontrolled gelation time, variation in gelation due to shear degradation, and gelant compositional changes induced by contact with reservoir minerals and fluids. PPGs can be controlled for strength and size, and they are environmentally friendly. Further, their stability is not sensitive to the reservoir's minerals and formation water salinity.

PPGs usually have only one component during injection, so they do not require the injection facilities and instruments needed to dissolve and mix polymers and crosslinkers in conventional gel systems. The simple injection operation processes and surface facilities can significantly reduce operational and labor costs (Bai, 2008).

Various types of preformed gels are commercially available; the major differences among them are particle size, swelling time, and swelling ratio. These commercial gels include PPG (Coste et al. 2000; Bai et al. 2004, 2005; Zaitoun et al. 2007), pH-sensitive crosslinked polymers (Al-Anazi, 2002; Huh, 2005), preformed bulk gels (Seright et al. 2004, 2005), microgels (Chauveteau et al. 2000, 2001), partially preformed gels (Sydansk et al. 2004), swelling millimeter-sized polymer grains (e.g., Diamond Seal®), and swelling micron-sized polymers such as Bright Water® (Pritchett, 2003; Frampton, 2004). Most of these gels have been applied to various reservoirs with satisfactory results.

**2.4.2 Gel Applications.** Seright et al. (2001) reported many successful gel treatments. They evaluated 274 gel treatments conducted in naturally fractured carbonate formations. The median water-to-oil ratio (WOR) was 82 before the treatment, 7 shortly after the treatment, and 20 a year or two after treatment.

Oil production increased following treatment and remained above pretreatment levels for 1 to 2 years. Thomas et al. (2000) reported that an initial investment of $231,000 for gel treatments resulted in incremental profits of $1.7-2.3 million over a two-year period.

**2.4.3 DPR Properties of Gels / Polymers.** Gel properties may vary over several stages during the course of gel treatment. For example, both the concentration and the molecular weight of polymer may vary. Viscosity too, may vary; it affects the size of cracks or fractures that can be penetrated at a given pressure. It also permits injection of the material as a premixed gel.

The degree of crosslinking might change throughout a treatment. Density is also a significant factor, if the gel is too dense, it can sink too far into the water layer and lose its effectiveness. Also, setup time, which determines how far into the crack or fractures the gel will penetrate.

**2.4.4 DPR Mechanisms.** Stavland, Nilsson (2001) "Segregated Flow is the Governing Mechanism of Disproportionate Permeability Reduction in Water and Gas Shutoff" indicated that DPR normally reduces water permeability more than oil or gas permeability. It is most effective when used against water production caused by coning or in situations where the watered out layers are separated from the oil producing layers.

DPR treatment in situations with two-phase flow will cause an improved pressure drawdown because of water saturation buildup in the treated zone. The methods of Polymer is adsorption at the pore surface and the possibility to alter the wettability to more water-wet situation as well as some lubrication effects. Dehydration and swelling of polymer and gel, segregated flow of oil and water and stability between the differing capillary forces. DPR is observed for both single polymers and crosslinked gel.

On the contrary, when an oil-based gel is used, the oil permeability should be reduced more than water permeability. Liang et al. (1995a,b, 1997) linked the segregated pathways with DPR and the hydrophilic character of the porous medium. In water-wet media, the oil will flow preferentially through the larger pores, whereas the water will flow preferentially through the smaller channels and along the pore walls. Thus, a water-based gelant should preferentially invade the smaller paths, and an oil-based gelant should invade the larger paths.

DPR technology has been widely used to selectively control water production due to its unique function of reducing permeability to water much more than that to hydrocarbon in conventional hydrocarbon reservoirs and gas storage wells. The function of disproportionate permeability reduction is essential to polymers or gels when they are placed in production wells without protecting hydrocarbon-productive zones.

With existing technology, polymer gels may have its greatest value when treating production wells that intersect a fracture or fracture-like features (Seright 2006). Nonetheless, previous DPR researches were focused on conventional unfractured cores for two reasons: the first reason is that many people are still very interested in exploiting the DPR property to reduce excess water production from unfractured wells, and the second is that people target on fully blocking fractures while exploiting the DPR property in matrix where has minimized gel penetration for fractured wells.

Many mechanisms for polymer and polymer gel DPR have been proposed, mainly include: (1) gel swelling in water but shrinking in oil (Mennella 1998, Dawe and Zhang 1994, Sparlin and Hagen 1984, Gales 1994, Liang 1995); (2) Segregated flow path to water and oil in porous media (Liang and Seright, 1997, Liang 1995, White 1973 ; Schneider and Owens 1982; Nilsson 1998; Stavland and Nilsson, 2001); (3) Wall effect by which gels constrict water pathways more than oil pathways in a given pore (Liang and Seright 1997, Liang et al 1995, Zaitoun and Kohler 1988, 1989; Barreau 1996; Zaitoun et al. 1998); (4) Pore blocked by "gel-droplet" where gel droplets formed in pore bodies cause a higher pressure drop at the pore throat in the wetting phase than in the nonwetting one (Liang and Seright 2001, Nilsson et al. 1998); (5) Gel dehydration during oil breakthrough (Seright 2006, 2008; Dawe and Zhang 1994, Green 1998, Willhite 2002); and others, such as wettability alteration by gel (Zaitoun 1998), Lubrication effect (Sparklin and Hagen 1984), etc.

DPR mechanisms have been argued for long time due to different core models and experimental design used by different researchers. Moreover, all the previous experiments were performed either in consolidated cores, sand-packed cores or visual pore-networked micromodels.

Near wellbore gas flow is usually non-Darcy flow due to high flow rate. However, all the previous work was focused on Darcy flow except for a couple of recent publications by Dr. Zaitoun's group (Elmkies 2002, Blanchard 2007). They studied the effect of polymer adsorption in a gas/water flow in non-Darcy regimes in a homogenous silicon carbide powders cores. But the study of Darcy and non-Darcy effect on DPR in fractured systems has not been reported in their publications.

White et al. (1973) suggested that DPR might be caused by water and oil flowing through segregated pathways, i.e., in a porous medium the pathways preferentially taken by water and oil are governed by wettability, pore size, and saturation. Therefore, water flows through the water-open pathways, while some of the oil pathways remain connected by oil and inaccessible to water. If this scenario is valid, a water-based gelant primarily follows the pathways available to water. Hence, after treatment these paths will be filled with gel. Some oil pathways however, must remain open after the treatment for the oil to flow through. Therefore, the water-based gel will reduce water permeability much more than oil permeability.

When oil and water are flowing simultaneously at a given fractional flow, fluid partitioning should naturally occur. The experiments of Liang et al. (1995a,b) showed that, depending on the fractional flow, the wettability, the base of the gelant, and water-relative permeability may or may not be preferentially reduced.

Nilsson et al. (1998) conducted a mechanistic study of DPR using quartz, sand, and Teflon powder to simulate strong water-wet and oil-wet porous media. Their experiments showed that a water-based polyacryalmide gel reduced the permeability to water significantly more than to oil, and they attributed the DPR to the segregated pathways.

**2.4.5 Application Condition of DPR Treatment.** Seright et al. (2007) suggested that DPR treatment can be successfully applied where some degree of excessive water production problems when appearing either in oil or gas production wells. DPR can be applied using bullhead injection due to excessive water production instead of mechanical zone isolation. Also, DPR can be attractive for the application of a matrix rock that is nearby water producing fracture.

DPR is applicable for multizoned unfractured production well that has excessive water production because this treatment is useful for long term WSO. Furthermore, DPR can provide short-term decreased water oil ratio for production wells that are not fully watered out where the radial flow is appearing in the matrix rock; on the other hand, all these wells need to be engineered.

Polyacrylamide or polymer gels are widely used in DPR applications. In addition to the reservoir channel/streak permeability, formation water composition, concentration, and reservoir temperature. The selection of polymers for DPR applications also depends on the extend to how much the chemicals can reduce permeability to water more than to hydrocarbon.

Many polymers were evaluated for this purpose (Bai 2007, Kalfayan and Qu 2008, Rousseau 2005, Seright 2006, Willhite 2008, Zitha 2006). For example, Seright (2006) tested the DPR performance of a few Cr(III)-Acetate-HPAM formulations in Berea sandstone and found that water resistance factor Frrw (the ratio of water permeability before gel treatment to that after treatment) is more than 2,000, but ultimate oil resistance factor (Frro) is only 2 or less.

Willhite's group (Nyuyen 2006) studied the effects of gelant compositions and pressure gradients of water and oil on DPR of sandpacks with polyacrylamide-chromium acetate gels, and found that increased gel composition concentration increased selectivity. However, previous studies about the magnitude of DPR were most focused on the oil/water system, but little attention has been paid to the gas/water system.

# 3. NUMERICAL RESERVOIR MODEL

## 3.1 MODEL DESCRIPTION

In order to accurately model the difference in reduction of relative permeability by using gel or polymer, it is necessary not only to use a reliable simulator, but also to take the inherent mechanisms into account. In this study, an existing simulator (CMG IMEX, Version 2008.10) is employed to model the relative permeability modification disproportion reduction water shutoff treatment for oil recovery with the incorporation of relative permeability. Since fluid volumes need to be determined in the displacement process, a three-dimensional (3D) model is used for the simulation of the relative permeability modification. Figure 3.1 shows the original relative permeability of water and oil and Figure 3.2 illustrates the 3D view of the numerical model. In this section, the models were applied to four different cases, case 1 which is linear flow for one layer, case 2 which is five spot for one layer, case 3 which is linear flow for two layers, and case 4 which is five spot for two layers, and each case has two scenarios. In scenario 1, the relative permeability of water was reduced by 20 times through injected gel or polymer when applying the water shutoff treatment. In scenario 2, the relative permeability of water was reduced by 60 times through injected gel or polymer when applying the water shutoff treatment. In both scenarios, the relative permeability of oil was reduced by 2 times.

**3.1.1 Case 1: Linear Flow for One Layer.** Case 1 was created with one layer and given specific physical properties. The porosity was set to 0.25%. The absolute permeability in the I direction was equal to 500 md, in the J direction was equal to 500 md, and in the K direction was 75 md. A regular coordinate system having three dimensions (i, j, k) was applied to all of the model reservoirs in the case. The number of grid blocks in the x direction was 100, the number of grid blocks in the y direction was 5, and the number of grid blocks in the z direction was 20. The total number of grid blocks was 10,000. Each block in the grid had the size of 10 feet in the x direction, 10 feet in the y direction, and 10 feet in the z direction. Figure 3.2 illustrates the 3D view of the numerical model of case 1. In all cases, reservoir temperature, oil density, gas density, water density, water formation volume factor, water compressibility, reference pressure for water, water viscosity, reference pressure, reference depth, phase contact of water-oil contact, datum depth and bubble point pressure are shown in Table 3.1. There were two wells, one producer located in block (1, 3, 1), and one injector located in block (100, 3, 1). The flow type in these wells was set as linear flow for this case. The locations of these wells are shown in Figure 3.3.

**3.1.2 Case 2: Five Spot for One Layer.** Case 2 was created for one layer and given specific physical properties. The porosity was set to 0.25%. The absolute permeability in the I direction was equal to 500 md, in the J direction was equal to 500 md, and in the K direction was 75 md. A regular coordinate system having three dimensions (i, j, k) was applied to all of the model reservoirs in all cases. The number of grid blocks in the x direction was 20, the number of grid blocks in the y direction was 20, and the number of grid blocks in the z direction was 20. The total number of grid blocks was 8,000. Each block in the grid had the size of 10 feet in the x direction, 10 feet in the y direction, and 10 feet in the z direction. Figure 3.4 illustrates the 3D view of the numerical model. There were two wells, one producer located in block (1, 20, 1), and one injector located in block (20, 1, 1). The locations of these wells are shown in Figure 3.5.

**3.1.3 Case 3: Linear Flow for Two Layers.** Case 3 was built for two layers and given specific physical properties. The porosity was set to 0.25%. In the upper layer the absolute permeability in the I direction was equal to 500 md, in the J direction was equal to 500 md, and in the K direction was 75 md. In the lower layer the absolute permeability in the I direction was equal to 1000 md, in the J direction was equal to 1000 md, and in the K direction was 150 md. A regular coordinate system having three dimensions (i, j, k) was applied to all of the model reservoirs in all cases. The number of grid blocks in the x direction was 100, the number of grid blocks in the y direction was 5, and the number of grid blocks in the z direction was 20. The total number of grid blocks was 10,000. Each block in the grid had the size of 10 feet in the x direction, 10 feet in the y direction, and 10 feet in the z direction. Figure 3.6 illustrates the 3D view of the numerical model. There were two wells, one producer located in block (1, 3, 1), and one injector located in block (100, 3, 1). The flow type in these wells was set as linear flow for this case. The locations of these wells are shown in Figure 3.3.

**3.1.4 Case 4: Five Spot for Two Layers.** Case 4 was built for two layers and given specific physical properties. The porosity was set to 0.25%. In the upper layer, the absolute permeability in the I direction was equal to 500 md, in the J direction was equal to 500 md, and in the K direction was 75 md. In the lower layer, the absolute permeability in the I direction was equal to 1000 md, in the J direction was equal to 1000 md, and in the K direction was 150 md. A regular coordinate system having three dimensions (i, j, k) was applied to all of the model reservoirs in all cases. The number of grid blocks in the x direction was 20, the number of grid blocks in the y direction was 20, and the number of grid blocks in the z direction was 20. The total number of grid blocks was 8,000. Each block in the grid had the size of 10 feet in the x direction, 10 feet in the y direction, and 10 feet in the z direction. Figure 3.7 illustrates the 3D view of the numerical model. There were two wells, one producer located in block (1, 20, 1), and one injector located in block (20, 1, 1). The locations of these wells are shown in Figure 3.5.

## 3.2 NUMERICAL PROCEDURES

The CMG IMEX, Version 2008 was used to model relative permeability modification for water in a reservoir in order to compare the effect of changing relative permeabilities water and oil production in the simulation study. In case 1 and 3 the model reservoir was divided into 100 grid in the I direction, 5 grid in the J direction, and 20 grid in the K direction. In case 2 and 4 the model reservoir was divided to 20 grid in the I direction, 20 grid in the J direction, and 20 grid in the K direction. CMG IMEX was used to simulate a study for relative permeability modification, also known as disproportionate permeability reduction or water shutoff treatment. One injection well was created in same grid location (1, 3, 1) in both cases 1 and 3, and was created in the same grid location (1, 20, 1) in both cases 2 and 4 for water flooding. One production well was created in the same grid location (100, 3, 1) in both cases 1 and 3, and was created in the same grid location (20, 1, 1) in both cases 2 and 4 for producing oil. The water flooding was applied until a 95% water cut was reached. The reservoir was injected with 200 bbl/day of water and produced 200 bbl/day of liquid. There were four different cases applied to the simulation model. The oil in place was 236,920 STB. The relative permeability in each case was modified based on the relative permeability for the base case as shown in Figure 3.1.

**3.2.1 Case 1 (Linear Flow / One Layer) Scenario 1.** Scenario 1 was created with linear flow and one layer, with the same permeability and porosity as the rest of the reservoir. The relative permeability was reduced by 20 times in water and by 2 times in oil, as shown in Figure 3.8. The gel polymer radius was 39.9 ft and the pore volume was 250 $ft^3$ as shown in Figure 3.10.

**3.2.2 Case 1 (Linear Flow / One Layer) Scenario 2.** Scenario 2 was created with linear flow and one layer, with the same permeability and porosity as the rest of the reservoir. The relative permeability was reduced by 60 times in water and by 2 times in oil, as shown in Figure 3.9. The gel polymer radius was 39.9 ft and the pore volume was 250 $ft^3$ as shown in Figure 3.10.

**3.2.3 Case 2 (Five Spot / One Layer) Scenario 1.** Scenario 1 was created with five spot and one layer, with the same permeability and porosity as the rest of the reservoir. The relative permeability was reduced by 20 times in water and by 2 times in oil, as shown in as shown in Figure 3.8. The gel polymer radius was 12.6 ft and the pore volume was 5 $ft^3$ as shown in Figure 3.11.

**3.2.4 Case 2 (Five Spot / One Layer) Scenario 2.** Scenario 2 was created with five spot and one layer, with the same permeability and porosity as the rest of the reservoir. The relative permeability was reduced by 60 times in water and by 2 times in oil, as shown in, as shown in Figure 3.9. The gel polymer radius was 12.6 ft and the pore volume was 5 $ft^3$ as shown in Figure 3.11.

**3.2.5 Case 3 (Linear Flow / Two Layers) Scenario 1.** Scenario 1 was created with linear flow and two layers, with two different permeabilities. The permeability of the upper layer was less than the permeability of the bottom layer. The porosity of the entire reservoir was the same. The relative permeability was reduced by 20 times in water and by 2 times in oil, as shown in, Figure 3.8. The gel polymer radius was 39.9, 56.43 ft and the pore volume was 375 $ft^3$ as shown in Figure 3.12.

**3.2.6 Case 3 (Linear Flow / Two Layers) Scenario 2.** Scenario 2 was created with linear flow and two layers, with two different permeabilities. The permeability of the upper layer was less than the permeability of the bottom layer. The porosity of the entire reservoir was the same The relative permeability was reduced by 60 times in water and by 2 times in oil, as shown in, Figure 3.9. The gel polymer radius was 39.9, 56.43 ft and the pore volume was 375 $ft^3$ as shown in Figure 3.12.

**3.2.7 Case 4 (Five Spot / Two Layers) Scenario 1.** Scenario 1 was created with five spot and two layers, with two different permeabilities. The permeability of the upper layer was less than the permeability of the bottom layer. The porosity of the entire reservoir was the same. The relative permeability was reduced by 20 times in water and by 2 times in oil, as shown in, Figure 3.8. The gel polymer radius was 12.6, 25.2 ft and the pore volume was 50 $ft^3$ as shown in Figure 3.13.

**3.2.8 Case 4 (Five Spot / Two Layers) Scenario 2.** Scenario 2 was created with five spot and two layers, with two different permeabilities. The permeability of the upper layer was less than the permeability of the bottom layer. The porosity of the entire reservoir was the same.  The relative permeability was reduced by 60 times in water and by 2 times in oil, as shown in, Figure 3.9. The gel polymer radius was 12.6, 25.2 ft and the pore volume was 50 $ft^3$ as shown in Figure 3.13.

## 3.3 RESULTS AND DISCUSSION

**3.3.1 Linear Flow One Layer: Scenario 1.** The relative permeability was reduced by 20 times with water and by 2 times with oil. The simulator run at the water cut reached 60%, 70%, 80%, and 90% for four different runs. The water shutoff treatment was worked by injecting gel or polymer which means the relative permeability of water was decreased, and the water cut was decreased over different periods of time during shutoff treatment. Table 3.2 shows the cumulative oil production during the effective period of water shutoff at the same RPM radius and the same volume. In this scenario the best modification was at water cut 60%, which was effective for a period of 428 days and improved the total oil production by 20,529 STB. Moreover the worst modification scenario was at water cut 90%, it was only effective for a shorter period of 99 days and there was not much improvement in the cumulative oil production due to most of the layers being flooded by water before RPM was made. Figure 3.14 shows that the cumulative oil production was increased when the water cut was decreased. Figure 3.15 confirms the results that when the water cut was lower, then there was higher oil production over longer periods of time. This was due to the water shutoff treatment being used at an early stage of oil production, before the water could reach breakthrough in the most of the layers. The water shutoff treatment results vary with changing the water cut percentage. Oil recovery was increased by 8.6% in the case of the lowest water cut of 60% during effective period, as shown in Figure 3.16.

**3.3.2 Linear Flow One Layer: Scenario 2.** The relative permeability was reduced by 60 times with water and by 2 times with oil. The simulator run at the water cut reached 60%, 70%, 80%, and 90% for four different runs. The water shutoff treatment was worked by injecting gel or polymer which means the relative permeability of water was decreased, and the water cut was decreased over different periods of time during shutoff treatment. Table 3.3 shows the cumulative oil production during the effective period of water shutoff at the same RPM radius and the same volume. In this scenario the best modification was still at water cut 60%, which was effective for a period of 376 days and improved the total oil production by 21,945 STB. Moreover the worst modification scenario was also at water cut 90%, it was only effective for short period of 95 days and there was not much improvement in the cumulative oil production due to most of the layers being flooded by water before RPM was made. Figure 3.17 shows that the cumulative oil production was increased when the water cut was decreased. Figure 3.18 confirms the results that when the water cut was lower, then there was higher oil production over longer periods of time. This was due to the water shutoff treatment being used at an early stage of oil production, before the water could reach breakthrough in the most of the layers. The water shutoff treatment results vary with changing the water cut percentage. Oil recovery was increased by 9.3% in the case of the lowest water cut of 60% during effective period, as shown in Figure 3.19.

**3.3.3 Comparison of Linear Flow (Case 1).** Table 3.4 provides a summary and comparison of cumulative oil production and the oil recovery factor for linear flow in one layer and a different relative permeability modifications. Figure 3.20 shown the best scenario at final oil recovery when reduced the relative permeability of water by 60 times at water cut 60% compared with when reduced the relative permeability of water by 20 times and different water cut.

As shown, the best scenario is for the relative permeability to water reduction by 60 times and at the lowest water cut of 60%, where the cumulative oil production went from 158,979 STB and increased to 172,292 STB, and the oil recovery factor was improved by 8.4%. The cumulative oil production was increased as shown in Figure 3.21 compared with base case 1. After treatment the water cut was reduced and then it returned to pretreatment decline rate as shown in Figure 3.22. The result of the oil recovery factor was significantly increased as shown in Figure 3.23. Also Figure 3.24 shown the best scenario during effective period when reduced the relative permeability of water by 60 times at water cut 60% compared with when reduced the relative permeability of water by 20 times and different water cut.

**3.3.4 Five Spot One Layer: Scenario 1.** The relative permeability was reduced by 20 times with water and by 2 times with oil. The simulator run at the water cut reached 60%, 70%, 80%, and 90% for four different runs. The water shutoff treatment was worked by injecting gel or polymer which means the relative permeability of water was decreased, and the water cut was decreased over different periods of time during shutoff treatment. Table 3.5 shows the cumulative oil production during the effective period of water shutoff at same RPM radius and same volume. In this scenario the best modification was still at water cut 60%, which was effective for a period of 976 days and improved the total oil production by 45,903 STB. Moreover the worst modification scenario was also at 90% water cut, it was only effective for a shorter period of 550 days and there was not much improvement in the cumulative oil production due to most of the layers being flooded by water before RPM was made. Figure 3.25 shows that the cumulative oil production was increased when the water cut was decreased. Figure 3.26 confirms the results that when the water cut was lower, then there was higher oil production over longer periods of time. This was due to the water shutoff treatment being used at an early stage of oil production, before the water could reach breakthrough in the most of the layers. The water shutoff treatment results vary with changing the water cut percentage. Oil recovery was increased by 19.4% in the case of the lowest water cut of 60% during effective period, as shown in Figure 3.27.

**3.3.5 Five Spot One Layer: Scenario 2.** The relative permeability was reduced by 60 times with water and by 2 times with oil. The simulator run at the water cut reached 60%, 70%, 80%, and 90% for four different runs. The water shutoff treatment was worked by injecting gel or polymer which means the relative permeability of water was decreased, and the water cut was decreased over different periods of time during shutoff treatment. Table 3.6 shows the cumulative oil production during the effective period of water shutoff at the same RPM radius and the same volume. In this scenario the best modification was still at water cut 60%, which was effective for a period of 837 days and improved the total oil production by 48,968 STB. The worst modification scenario was at 90% water cut, as it was only effective for a shorter period of 498 days and there was not much improvement in the cumulative oil production due to most of the layers being flooded by water before RPM was made. Figure 3.28 shows that the cumulative oil production was increased when the water cut was decreased. Figure 3.29 confirms the results that when the water cut was lower, then there was higher oil production over longer periods of time. This was due to the water shutoff treatment being used at an early stage of oil production, before the water could reach breakthrough in the most of the layers. The water shutoff treatment results vary with changing the water cut percentage. Oil recovery was increased by 20.7% in the case of the lowest water cut of 60% during effective period, as shown in Figure 3.30.

**3.3.6 Comparison of Five Spot One Layer (Case 2).** Table 3.7 provides a summary and comparison of cumulative oil production and the oil recovery factor for five spot in one layer and a different relative permeability modifications. Figure 3.31 shown the best scenario at final oil recovery when reduced the relative permeability of water by 60 times at water cut 60% compared with when reduced the relative permeability of water by 20 times and different water cut.

As shown, the best scenario is for the relative permeability to water reduction by 60 times and at the lowest water cut of 60% , where the cumulative oil production went from 131,116 STB and increased to 170,694 STB, and the oil recovery factor was improved by 30.2%. It was significantly better than base case 2. The cumulative oil production was increased as shown in Figure 3.32 compared with base case 2. After treatment the water cut was reduced and then it returned to pretreatment decline rate as shown in Figure 3.33. The result of the oil recovery factor was significantly increased as shown in Figure 3.34. Also Figure 3.35 shown the best scenario during effective period when reduced the relative permeability of water by 60 times at water cut 60% compared with when reduced the relative permeability of water by 20 times and different water cut.

**3.3.7 Linear Flow Two Layers: Scenario 1.** The relative permeability was reduced by 20 times with water and by 2 times with oil. The simulator run at the water cut reached 60%, 70%, 80%, and 90% for four different runs. The water shutoff treatment was worked by injecting gel or polymer which means the relative permeability of water was decreased, and the water cut was decreased over different periods of time during shutoff treatment. Table 3.8 shows the cumulative oil production during the effective period of water shutoff at same RPM radius and same volume. In this scenario the best modification was at water cut 60%, which was effective for a period of 952 days and improved the total oil production by 20,541 STB. Moreover the worst modification scenario was at 90% water cut, it was only effective for short period of 405 days and there was not much improvement in the cumulative oil production due to most of the layers being flooded by water before RPM was made. Figure 3.36 shows that the cumulative oil production was increased when the water cut was decreased. Figure 3.37 confirms the results that when the water cut was lower, then there was higher oil production over longer periods of time. This was due to the water shutoff treatment being used at an early stage of oil production, before the water could reach breakthrough in the most of the layers. The water shutoff treatment results vary with changing the water cut percentage. Oil recovery was increased by 8.7% in the case of the lowest water cut of 60 % during effective period, as shown in Figure 3.38.

**3.3.8 Linear Flow Two Layers: Scenario 2.** The relative permeability was reduced by 60 times with water and by 2 times with oil. The simulator run at the water cut reached 60%, 70%, 80%, and 90% for four different runs. The water shutoff treatment was worked by injecting gel or polymer which means the relative permeability of water was decreased, and the water cut was decreased over different periods of time during shutoff treatment. Table 3.9 shows the cumulative oil production during the effective period of water shutoff at same RPM radius and same volume. In this scenario the best modification was still at water cut 60%, which was effective for a period of 951 days and improved the total oil production by 23,283 STB. Moreover the worst modification scenario was also at 90% water cut, it was only effective for short period of 440 days and there was not much improvement in the cumulative oil production due to most of the layers being flooded by water before RPM was made. Figure 3.39 shows that the cumulative oil production was increased when the water cut was decreased. Figure 3.40 confirms the results that when the water cut was lower, then there was higher oil production over longer periods of time. This was due to the water shutoff treatment being used at an early stage of oil production, before the water could reach breakthrough in the most of the layers. The water shutoff treatment results vary with changing the water cut percentage. Oil recovery was increased by 9.8% in the case of the lowest water cut of 60 % during effective period, as shown in Figure 3.41.

**3.3.9 Comparison of Linear Flow Two Layers (Case 3).** Table 3.10 provides a summary and comparison of cumulative oil production and the oil recovery factor for linear flow in two layers and a different relative permeability modifications. Figure 3.42 shown the best scenario at final oil recovery when reduced the relative permeability of water by 60 times at water cut 60% compared with when reduced the relative permeability of water by 20 times and different water cut.

As shown, the best scenario is for the relative permeability to water reduction by 60 times and at the lowest water cut of 60%, where the cumulative oil production went from 145,165 STB and increased to 162,390 STB, and the oil recovery factor was improved by 11.9%. It was significantly better than base case 3. The cumulative oil production was increased as shown in Figure 3.43 compared with base case 3. After treatment the water cut was reduced and then it returned to pretreatment decline rate as shown in Figure 3.44. The result of the oil recovery factor was significantly increased as shown in Figure 3.45. Also Figure 3.46 shown the best scenario during effective period when reduced the relative permeability of water by 60 times at water cut 60% compared with when reduced the relative permeability of water by 20 times and different water cut.

**3.3.10 Five Spot Two Layers: Scenario 1.** The relative permeability was reduced by 20 times with water and by 2 times with oil. The simulator run at the water cut reached 60%, 70%, 80%, and 90% for four different runs. The water shutoff treatment was worked by injecting gel or polymer which means the relative permeability of water was decreased, and the water cut was decreased over different periods of time during shutoff treatment. Table 3.11 shows the cumulative oil production during the effective period of water shutoff at same RPM radius and same volume. In this scenario the best modification was at water cut 60%, which was effective for a period of 1406 days and improved the total oil production by 70,954 STB. Moreover the worst modification scenario was at 90% water cut, it was only effective for short period of 1141 days and there was not much improvement in the cumulative oil production due to most of the layers being flooded by water before RPM was made. Figure 3.47 shows that the cumulative oil production was increased when the water cut was decreased. Figure 3.48 confirms the results that when the water cut was lower, then there was higher oil production over longer periods of time. This was due to the water shutoff treatment being used at an early stage of oil production, before the water could reach breakthrough in the most of the layers. The water shutoff treatment results vary with changing the water cut percentage. Oil recovery was increased by 29.9% in the case of the lowest water cut of 60 % during effective period, as shown in Figure 3.49.

**3.3.11 Five Spot Two Layers: Scenario 2.** The relative permeability was reduced by 60 times with water and by 2 times with oil. The simulator run at the water cut reached 60%, 70%, 80%, and 90% for four different runs. The water shutoff treatment was worked by injecting gel or polymer which means the relative permeability of water was decreased, and the water cut was decreased over different periods of time during shutoff treatment. Table 3.12 shows the cumulative oil production during the effective period of water shutoff at same RPM radius and same volume. In this scenario the best modification was still at water cut 60%, which was effective for a period of 1361 days and improved the total oil production by 73,832 STB. Moreover the worst modification scenario was also at 90% water cut, it was only effective for short period of 1003 days and there was not much improvement in the cumulative oil production due to most of the layers being flooded by water before RPM was made. Figure 3.50 shows that the cumulative oil production was increased when the water cut was decreased. Figure 3.51 confirms the results that when the water cut was lower, then there was higher oil production over longer periods of time. This was due to the water shutoff treatment being used at an early stage of oil production, before the water could reach breakthrough in the most of the layers. The water shutoff treatment results vary with changing the water cut percentage. Oil recovery was increased by 31.2% in the case of the lowest water cut of 60% during effective period, as shown in Figure 3.52.

**3.3.12 Comparison of Five Spot Two Layers (Case 4).** Table 3.13 provides a summary and comparison of cumulative oil production and the oil recovery factor for five spot two layers and a different relative permeability modifications. Figure 3.53 shown the best scenario at final oil recovery when reduced the relative permeability of water by 60 times at water cut 60% compared with when reduced the relative permeability of water by 20 times and different water cut.

As shown, the best scenario is for the relative permeability to water reduction by 60 times and at the lowest water cut of 60% , where the cumulative oil production went from 98,696.6 STB and increased to 169,960 STB, and the oil recovery factor was improved by 72.2%. It was significantly better than base case 4. The cumulative oil production was increased as shown in Figure 3.54 compared with base case 4. After treatment the water cut was reduced and then it returned to pretreatment decline rate as shown in Figure 3.55. The result of the oil recovery factor was significantly increased as shown in Figure 3.56. Also Figure 3.57 shown the best scenario during effective period when reduced the relative permeability of water by 60 times at water cut 60% compared with when reduced the relative permeability of water by 20 times and different water cut.

**3.3.13 Comparison of Linear Flow and Five Spot One Layer (Case 1 and Case 2).** Table 3.14 provides a summary and comparison of cumulative oil and oil recovery factors at the end of relative permeability modification, with the water cut at 95% for linear flow and five spot one layer with different relative permeability modification. As shown, the cumulative oil and recovery factor is slightly better for case 1 and 2 where relative permeability was redused by 60 times and water cut 60% at five spot. The cumulative oil production was increased and the oil recovery factor was improved with the best result in this modification. Figure 3.58 shown the best scenario at final oil recovery when reduced the relative permeability of water by 60 times at water cut 60% case 2 five spot compared with when reduced the relative permeability of water by 20 times case 1 linear flow and different water cut.

**3.3.14 Comparison of Linear Flow and Five Spot Two Layers (Case 3 and Case 4).** Table 3.15 provides a summary and comparison of cumulative oil and oil recovery factors at end of relative permeability modification with water cut 95% for linear flow at five spot two layers with different relative permeability modification. As shown, cumulative oil and recovery factors are slightly better for cases 3 and 4 where relative permeability was redused by 60 times and water cut 60% and five spot. The cumulative oil production was increased and the oil recovery factor was improved with best results in this modification. Figure 3.59 shown the best scenario at final oil recovery when reduced the relative permeability of water by 60 times at water cut 60% case 3 five spot compared with when reduced the relative permeability of water by 20 times case 4 linear flow and different water cut.

**3.3.15 Impact of Gel Treatment Volume/Radius (Case 1).** Table 3.16 provides a summary and comparison of the cumulative oil production and the oil recovery factor for linear flow one layer at the end of the relative permeability modification with different gel tratments. The radius was 28.2, 39.9, and 56.43 ft and volume was 125, 250, and 500 $ft^3$. The cumulative oil and recovery factor is slightly better when the relative permeability modification radius was 56.43 ft and 500 $ft^3$ pore volume with the relative permeabilty of water reduced by 60 times and at water cut of 60%. It produced the largest amount of oil at the earliest time compared with other results.

Table 3.17 provides a summary and comparison of the impact of gel treatment volume/radius. The cumulative oil production and oil recovery factor during water shutoff tratment were improved when the relative permeability modification radius was 56.43 ft and the pore volume was 500 ft³ with relative prmeability of water decreased by 60 times and water cut 60%. The result of the water cut is shown in Figure 3.60. The water shutoff treatment did not last a long time, it only operated for a few months, but at the end of the simulation or during the water shutoff treatment, the cumulative oil progressed.

**3.3.16 Impact of Gel Treatment Volume/Radius (Case 2).** Table 3.18 provides a summary and comparison of the cumulative oil production and oil the recovery factor for five spot one layer at the end of the relative permeability modification with different gel treatments. The radius was 6.3, 12.6 and 25.2 ft and pore volume was 5, 20, and 80 ft³. The cumulative oil production and oil recovery factor is slightly better when the relative permeability modification radius was 25.2 ft and 80 ft³ pore volume with the relative permeabilty of water redused by 60 times and at water cut 60%.It produced the largest amount of oil at the earliest time compared with others results.

Table 3.19 provides a summary and comparison of the impact of gel treatment volume/radius. The cumulative oil production and oil recovery factor during water shutoff tratment were improved when the relative permeability modification radius was 25.2 ft and the pore volume was 80 ft³ with relative prmeability of water redused by 60 times and water cut 60%. The result of the water cut is shown in Figure 3.61. The water shutoff treatment did not last a long time, it only operated for a few months, but at the end of the simulation or during the water shutoff treatment, the cumulative oil progressed.

**3.3.17 Impact of Gel Treatment Volume/Radius (Case 3).** Table 3.20 provides a summary and comparison of the cumulative oil production and oil the recovery factor for linear flow two layers at the end of the relative permeability modification with different gel treatments. The radius was 28.2, 39.9, 56.43 and 79.8 ft and pore volume was 187.5, 375, and 750 $ft^3$. The cumulative oil production and oil recovery factor is slightly better when the relative permeability modification radius was 56.43, 79.8 ft and 750 $ft^3$ pore volume with the relative permeabilty of water redused by 60 times and at 60%. It produced the largest amount of oil at the earliest time compared with others results.

Table 3.21 provides a summary and comparison of the impact of gel treatment volume/radius. The cumulative oil production and oil recovery factor during water shutoff tratment were improved when the relative permeability modification radius was 56.4, 79.8 ft and 750 $ft^3$ and the pore volume with relative prmeability of water redused by 60 times and water cut 60%. The result of the water cut is shown in Figure 3.62. The water shutoff treatment did not last a long time, it only operated for a few months, but at the end of the simulation or during the water shutoff treatment, the cumulative oil progressed.

**3.3.18 Impact of Gel Treatment Volume/Radius (Case 4).** Table 3.22 provides a summary and comparison of the cumulative oil production and the oil recovery factor for five spot two layers at the end of the relative permeability modification with different gel treatments. The radius was 6.3, 12.6, 25.2 and 50.4 ft and pore volume was 12.5, 50, and 200 $ft^3$. The cumulative oil and the recovery factor is slightly better when the relative permeability modification radius was 25.2, 50.4 ft and 200 $ft^3$ pore volume with the relative permeabilty of water redused by 60 times and at water cut of 60%. It produced the largst amount of oil at earliest time compared with others results.

Table 3.23 provides a summary and comparison of the impact of gel treatment volumm/radius. The cumulative oil production and oil recovery factor during water shutoff tratmentwere improved when the relative permeability modification radius was 6.3, 12.6 and 25.2 ft with 12.5 and the pore volume was 50 $ft^3$ with relative prmeability of water redused by 60 times and water cut 60% and 25.2, 50.4 ft and the pore volume was 200 $ft^3$ with relative prmeability of water redused 20 times at water cut 60%. The result of the water cut is shown in Figure 3.63. The water shutoff treatment did not last a long time, it only operated for a few months, but at the end of the simulation or during the water shutoff treatment, the cumulative oil progressed.

**3.3.19 Effect of Gel Treatment on Water Saturation at Final Water Cut 95%.** Table 3.24 provides a summary of how the cumulative water injection at base case 1 decresed from 520.47 to 347.00 MSTB at case 1 with RPM and took less time to arrive at water cut 95% compared with base case 1 as shown in Figure 3.64 and Figure 3.65. Also how the cumulative water injection at base case 2decreased from 830.70 to 395.60 MSTB at case 2 with RPM and took time to arrived at water cut 95% compared with base case 2 as shown in Figure 3.66 and Figure 3.67. Als how the cumulative water injection at base case 3 decreced from 789.07 to 383.40 MSTB at case 3 with RPM and took less time to arived to water cut 95% compared with base case 3 as shown in Figure 3.68 and Figure 3.69. Finally,how the cumulative water production at base case 4 decreaced from 660.70 to 369.00 MSTB at case 4 with RPM and took less time to arrived to water cut 95% compared with base case 4 as showen in Figure 3.70 and Figure 3.71.

**3.3.20 Effect of Gel Treatment Before and After on Water Saturation.** The available evidence indicates that the gel polymer usually shifted the entire water relative permeability curve to lower values without significantly changing the residual oil saturation. In contrast, the position of the oil relative permeability curve was often unaffected by the gel polymer, except that the irreducible water saturation was increased due to the gel polymer injection. Therefore, as shown the same time period in Figure 3.73 gives an indication of an increase of water saturation in contrast with Figure 3.72 the base case. That is because during water shutoff treatment, the water was increased because the gel plucked the area near the wellbore so the water cannot move, which that means the mobility of the water is restricted; as a result, the drawdown pressure was increased so there is bore space can be filled by water and then it can move faster to fill the pore space. In addition, this theory applies for case 1 and case 1 with RPM in the same time period as in Figure 3.74 and Figure 3.75, we can observe the increase in water saturation after the gel treatment is injected. The water cut increased rabidly with water shutoff treatment.

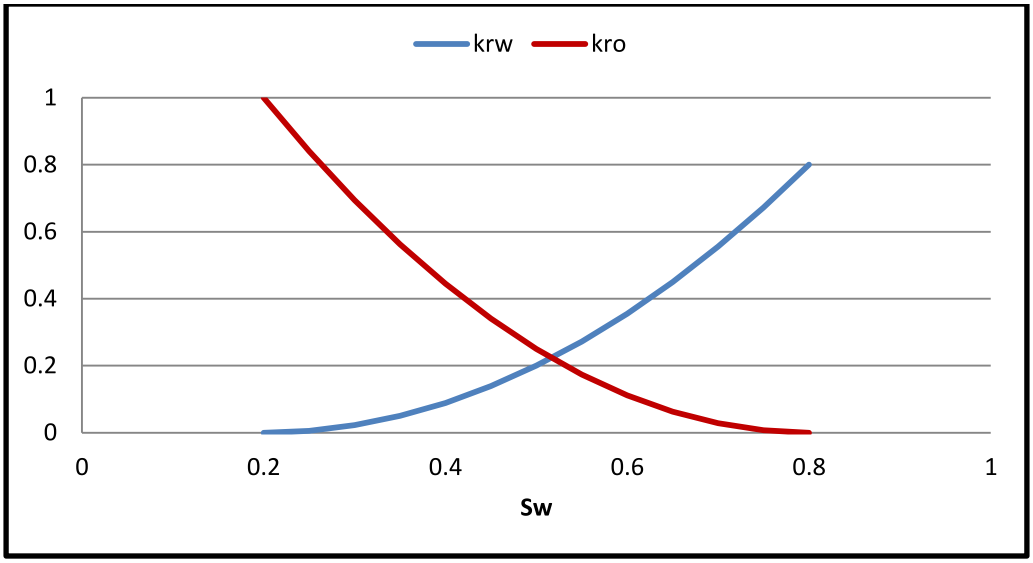


Figure 3.1 Relative Permeability.

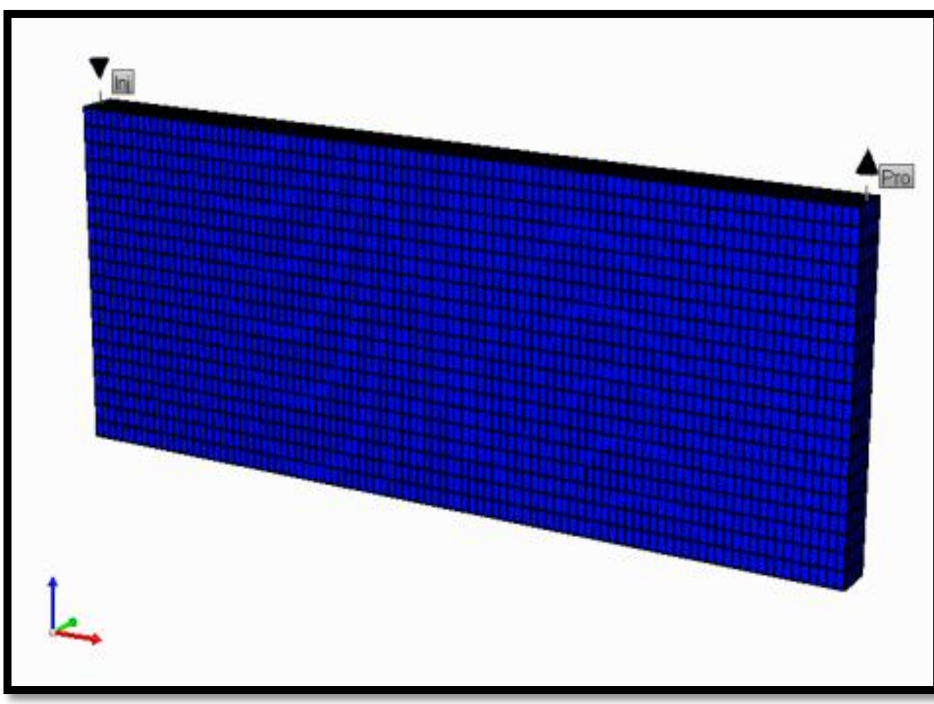


Figure 3.2 The 3D View of The Numerical Model (Linear Flow).

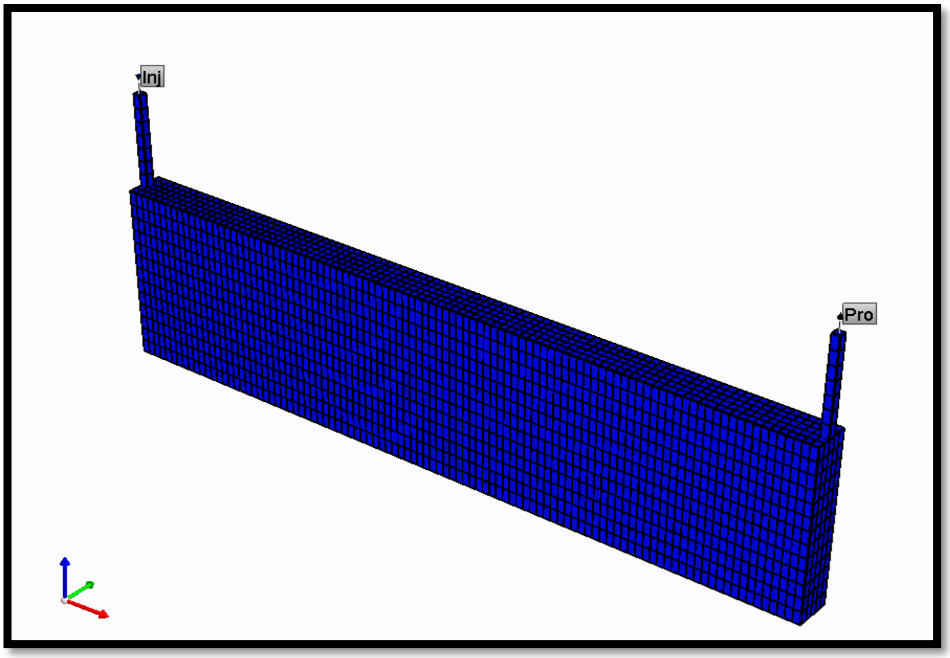


Figure 3.3 The 3D View of The Well Location (Case 1 and 3).

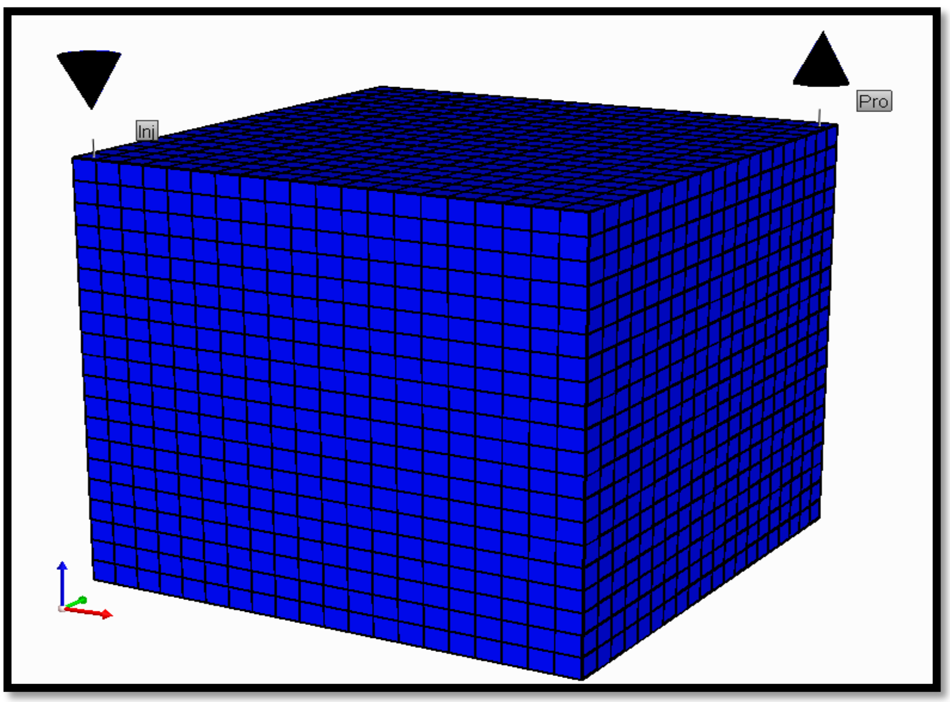


Figure 3.4 The 3D View of The Numerical Model (Five Spot).

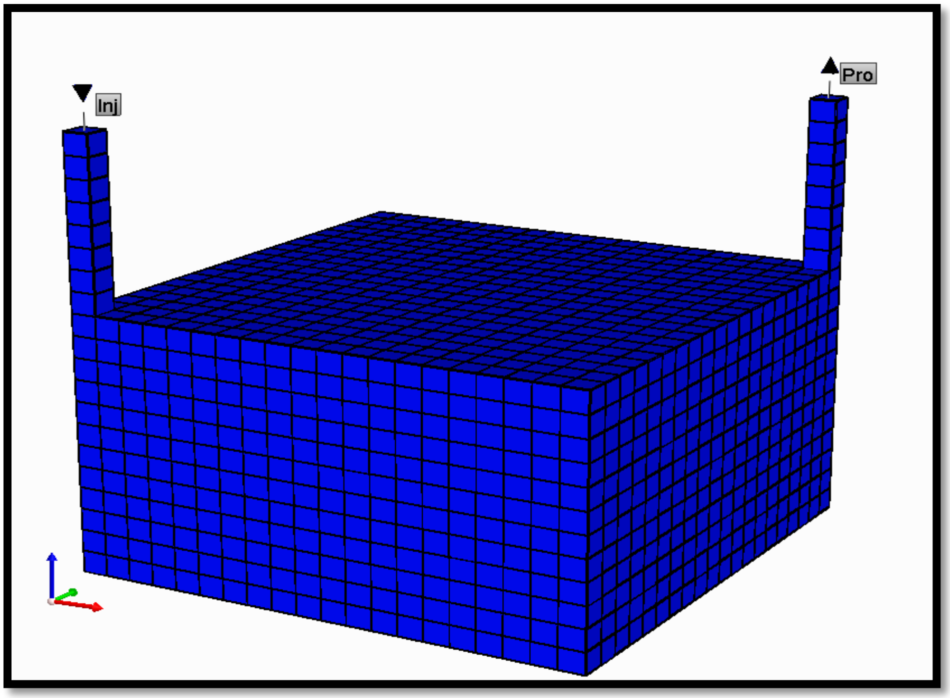


Figure 3.5 The 3D View of The Well Location (Five Spot Case 2 and 4).

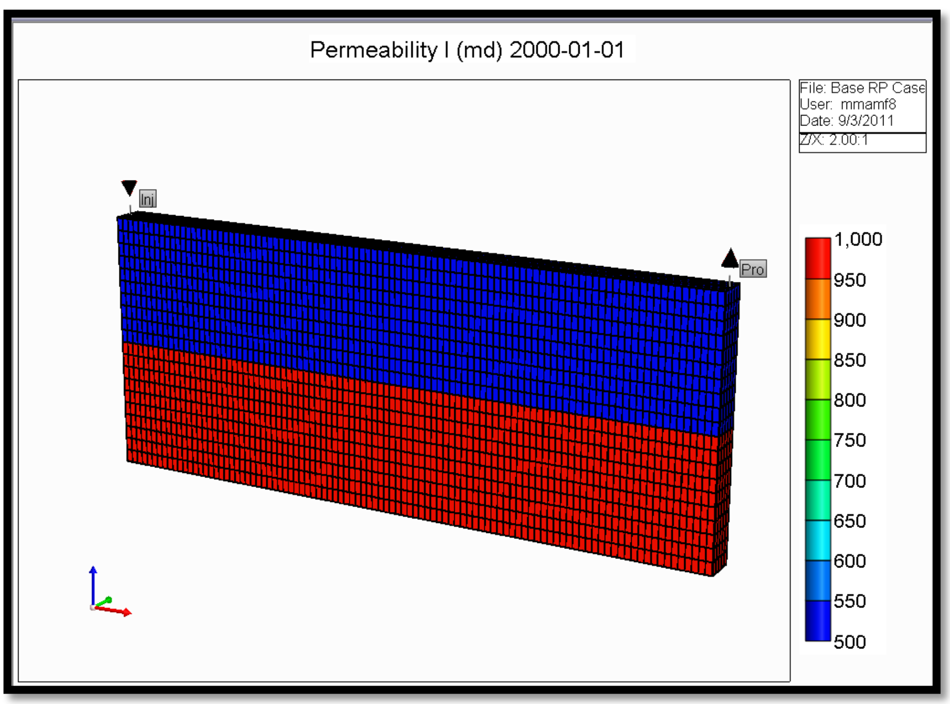


Figure 3.6 The 3D View of The Permeability of Two Layers (Linear Flow Case 3).

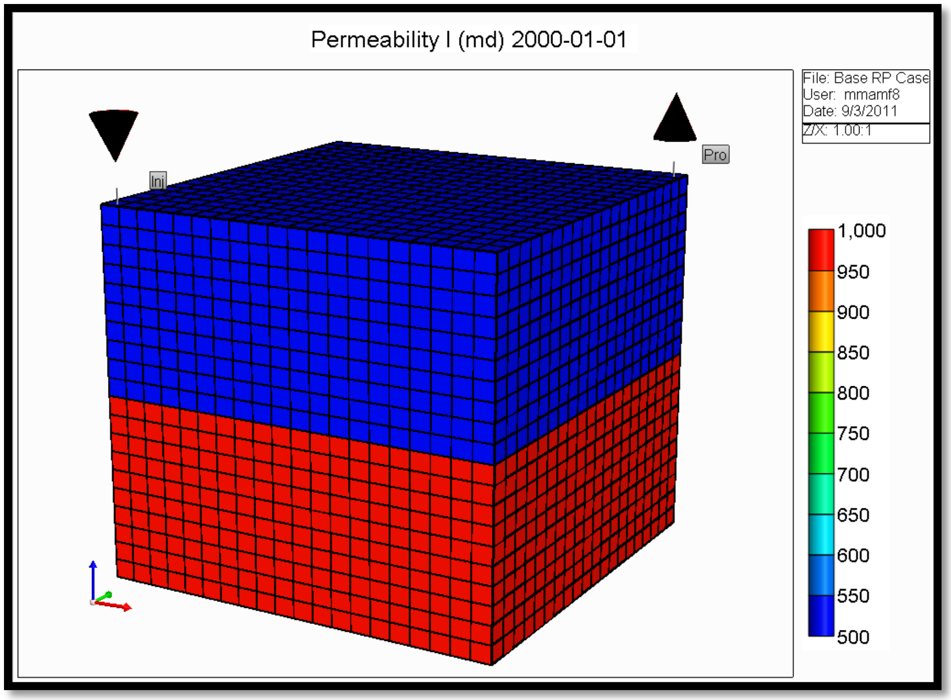


Figure 3.7 The 3D View of The Permeability of Two Layers (Five Spot Case 4).

Table 3.1 The Input Physical Properties

| | |
|---|---|
| Reservoir temperature (F) | 160 |
| Oil density (lb/ft3) | 51.4561 |
| Gas density (lb/ft3) | 0.05341 |
| Water density (lb/ft3) | 62.3179 |
| Water formation volume factor (RB/STB) | 1.00832 |
| Water compressibility (1/ps) | 2.7756e-006 |
| Ref. pressure for water (psi) | 5000 |
| Water viscosity (cp) | 0.432871 |
| Reference presser (psi) | 5200 |
| Reference depth (ft) | 11400 |
| Phase contact of Water-Oil contact (ft) | 11450 |
| Datum Depth (ft) | 11200 |
| Bubble point pressure (psi) | 3400 |

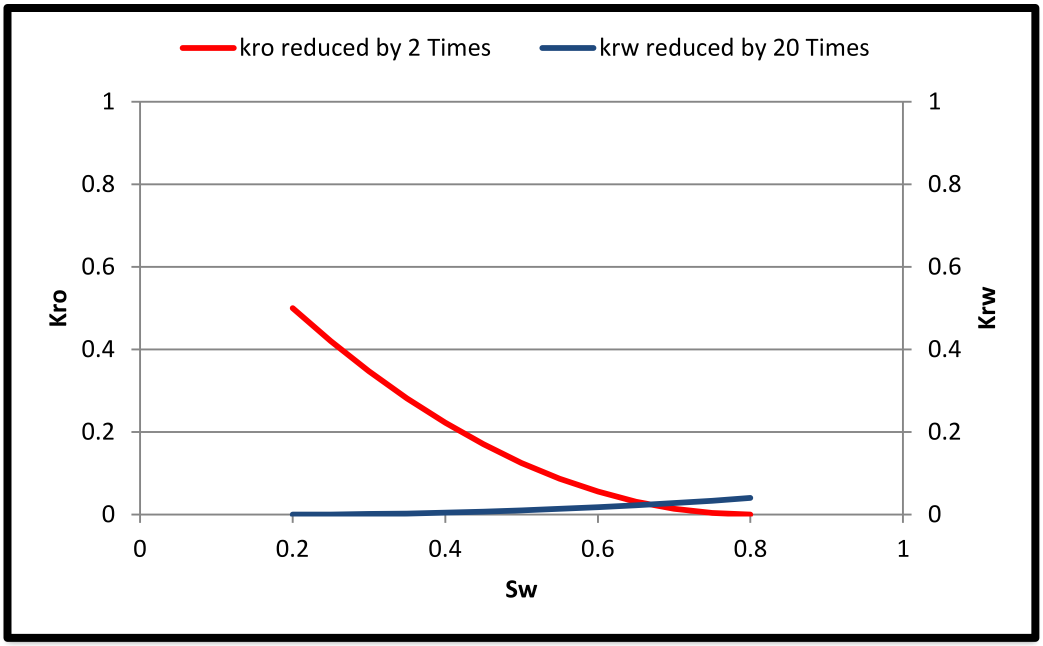


Figure 3.8 Oil and Water Relative Permeability Curves Before and After Gel Treatment Reduced The Relative Permeability of Water by 20 Times.

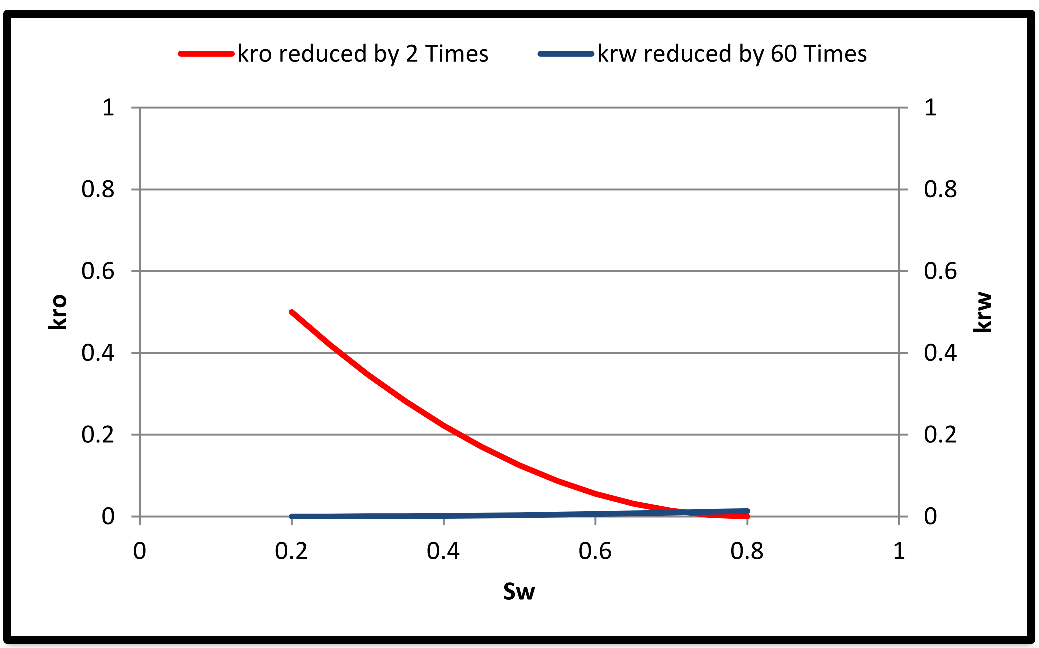


Figure 3.9 Oil and Water Relative Permeability Curves Before and After Gel Treatment Reduced The Relative Permeability of Water by 60 Times.

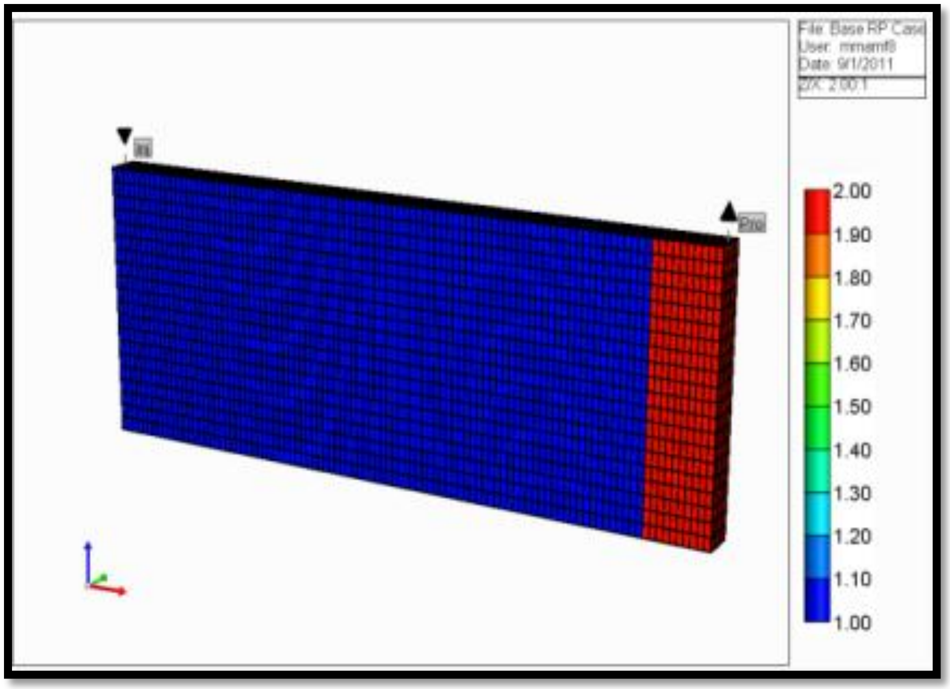


Figure 3.10  The 3D View of The Relative Permeability Modification Radius (Linear Flow Case 1).

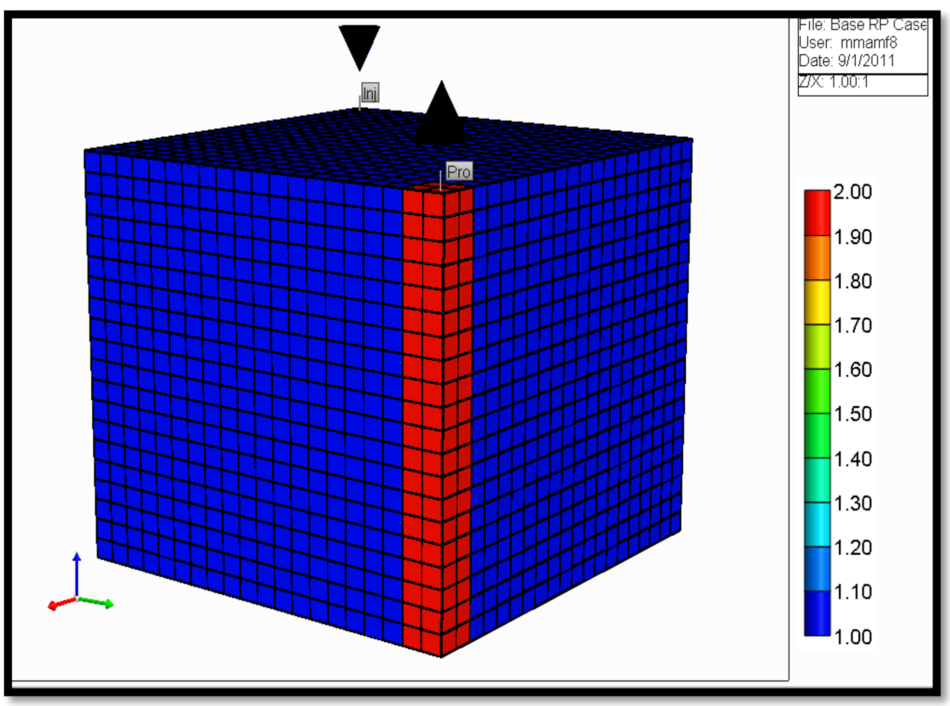


Figure 3.11The 3D View of Relative Permeability Modification Radius (Five Spot Case 2).

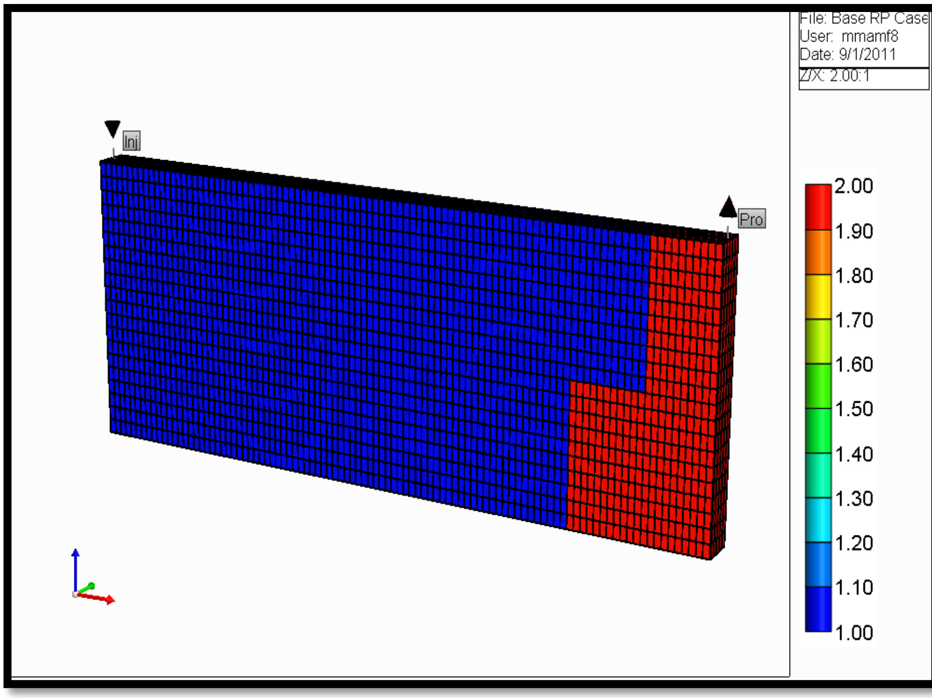


Figure 3.12 The 3D View of The Relative Permeability Modification Radius (Linear Flow Case 3).

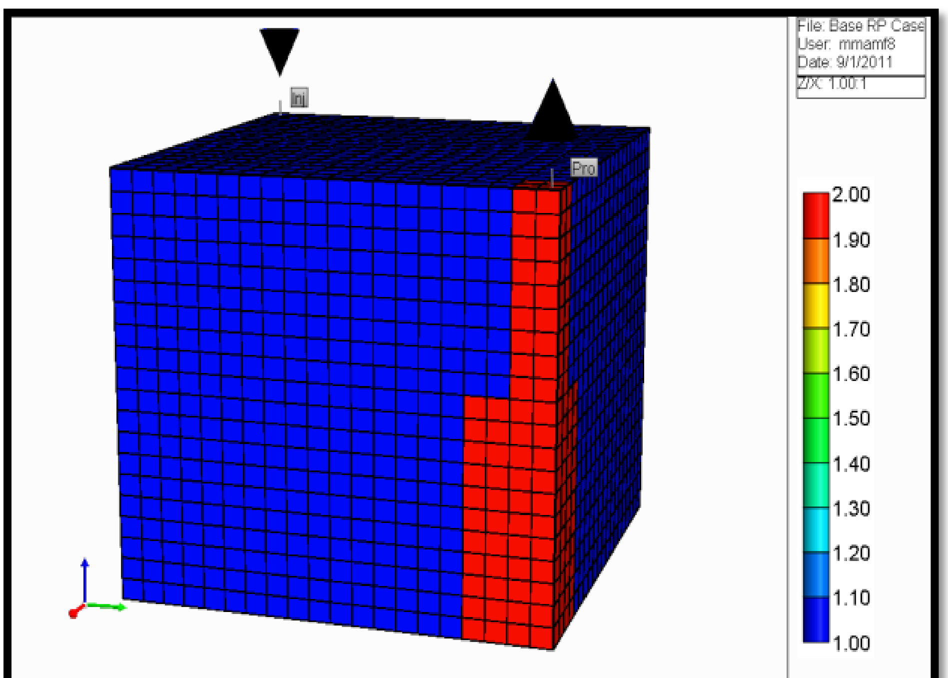


Figure 3.13 The 3D View of Relative Permeability Modification Radius (Five Spot Case 4).

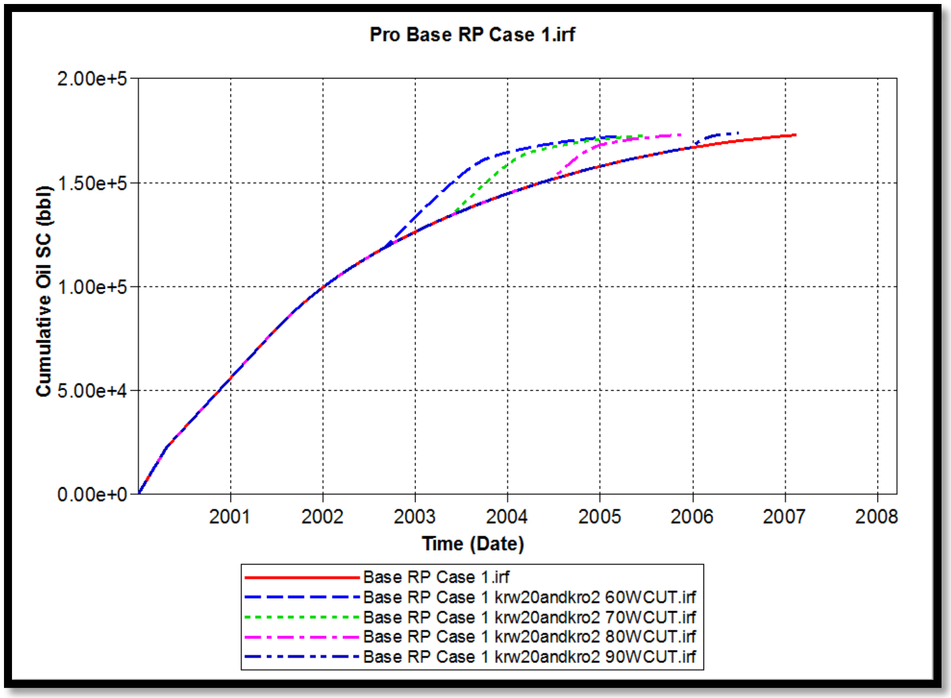


Figure 3.14 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 1 Scenario1).

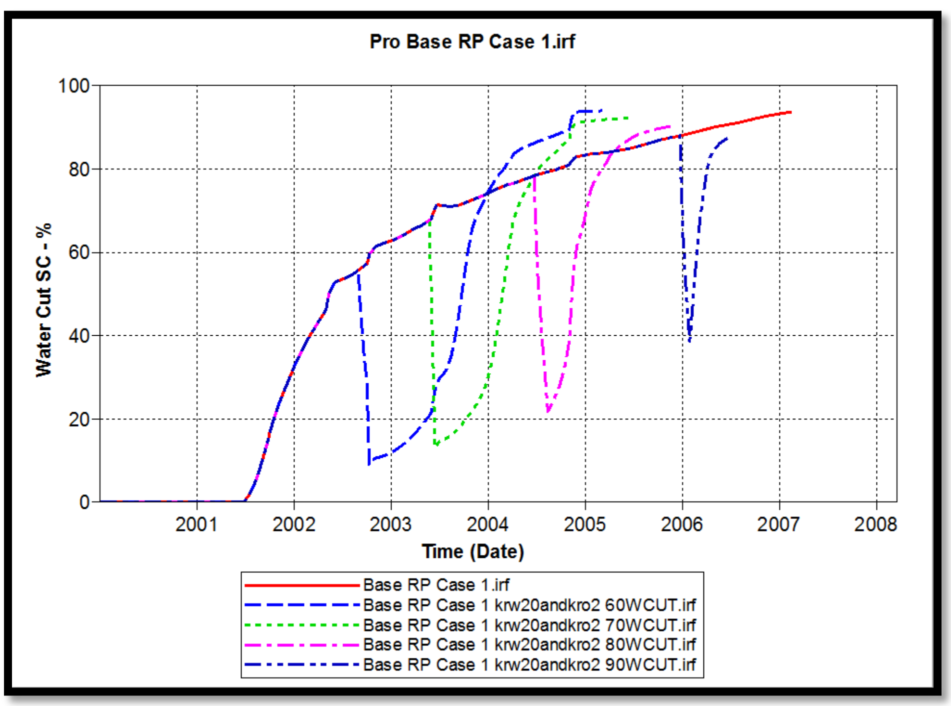


Figure 3.15 Water Cut (Case 1 Scenario 1).

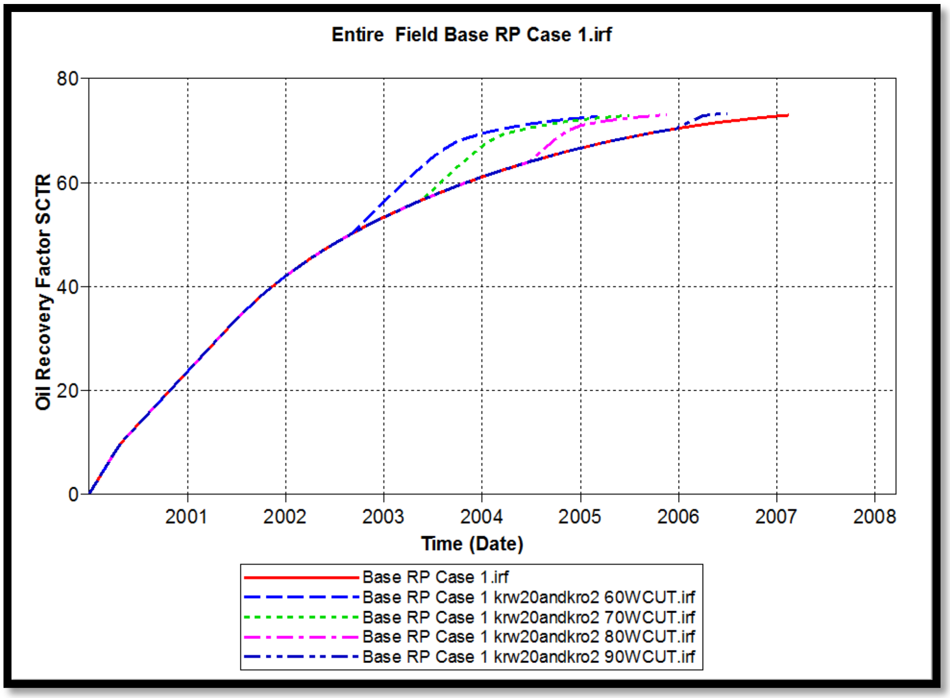


Figure 3.16 Oil Recovery Factor (Case 1 Scenario 1).

Table 3.2 Effect on Effective Period (days) and Corresponding Increased Oil Case 1 Scenario 1.

| RPM | Effective period (day) | RPM Radius (ft) | Volume of RPM ($ft^3$) | Total Oil production at Base Case | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/20,kro/2 60%WCUT | 428 | 39.9 | 250 | 23169 | 43698 | 20529 | 8.6 |
| krw/20,kro/2 70% WCUT | 313 | 39.9 | 250 | 14071 | 30307 | 16236 | 6.8 |
| krw/20,kro/2 80% WCUT | 206 | 39.9 | 250 | 6701 | 16968 | 10267 | 4.3 |
| krw/20,kro/2 90% WCUT | 99 | 39.9 | 250 | 1853 | 5925 | 4072 | 1.7 |

Table 3.3  Effect on Effective Period (days) and Corresponding Increased Oil Case 1 Scenario 2.

| RPM | Effect period (day) | RPM Radius (ft) | Volume of RPM ($ft^3$) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/60,kro/2 60% WCUT | 376 | 39.9 | 250 | 21148 | 43093 | 21945 | 9.3 |
| krw/60,kro/2 70% WCUT | 284 | 39.9 | 250 | 12946 | 30233 | 17287 | 7.3 |
| krw/60,kro/2 80% WCUT | 192 | 39.9 | 250 | 6349 | 17268 | 10919 | 4.6 |
| krw/60,kro/2 90% WCUT | 95 | 39.9 | 250 | 1780 | 6199 | 4419 | 1.9 |

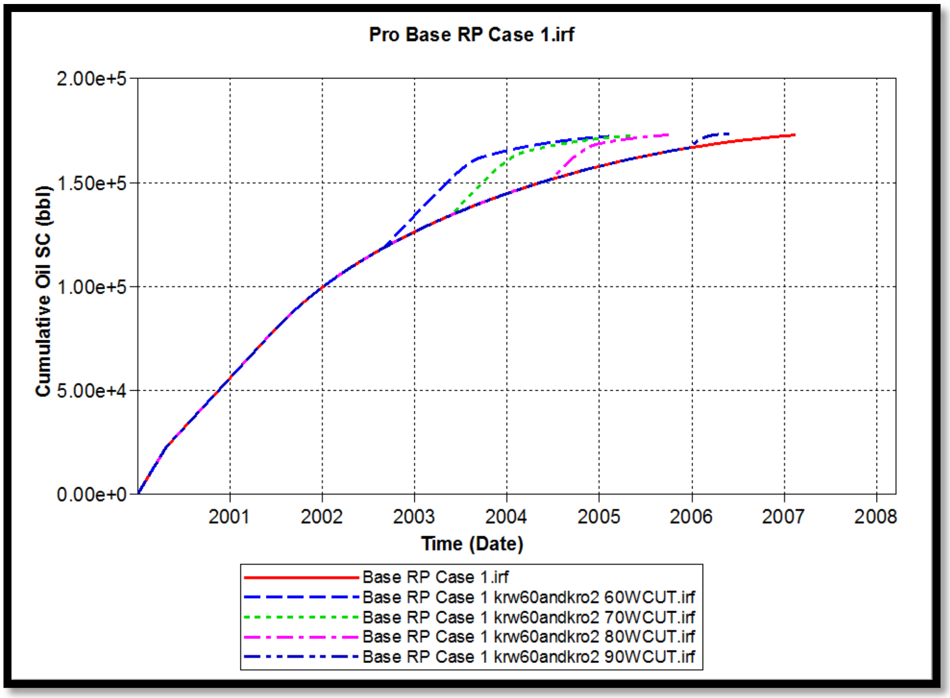


Figure 3.17 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 1 Scenario 2).

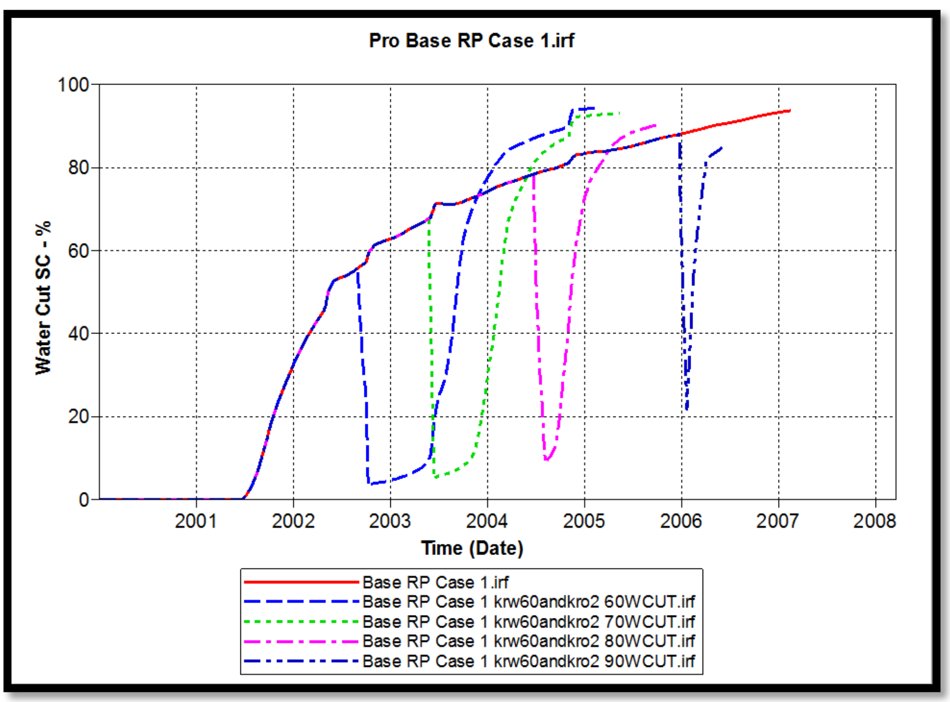


Figure 3.18 Water Cut (Case 1 Scenario 2).

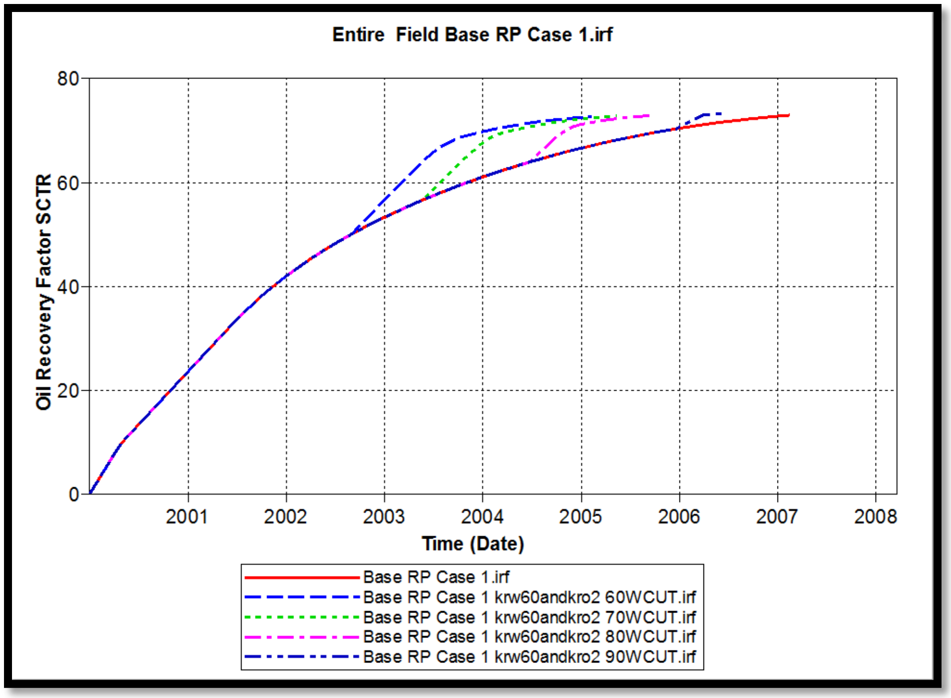


Figure 3.19 Oil Recovery Factor (Case1 Scenario 2).

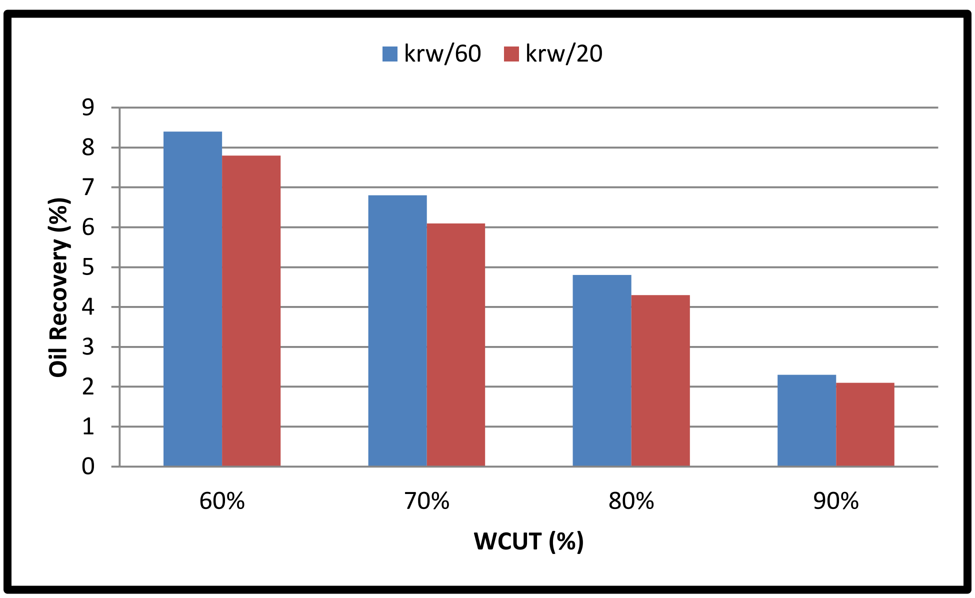


Figure 3.20 Comparison of Oil Recovery for Case 1.

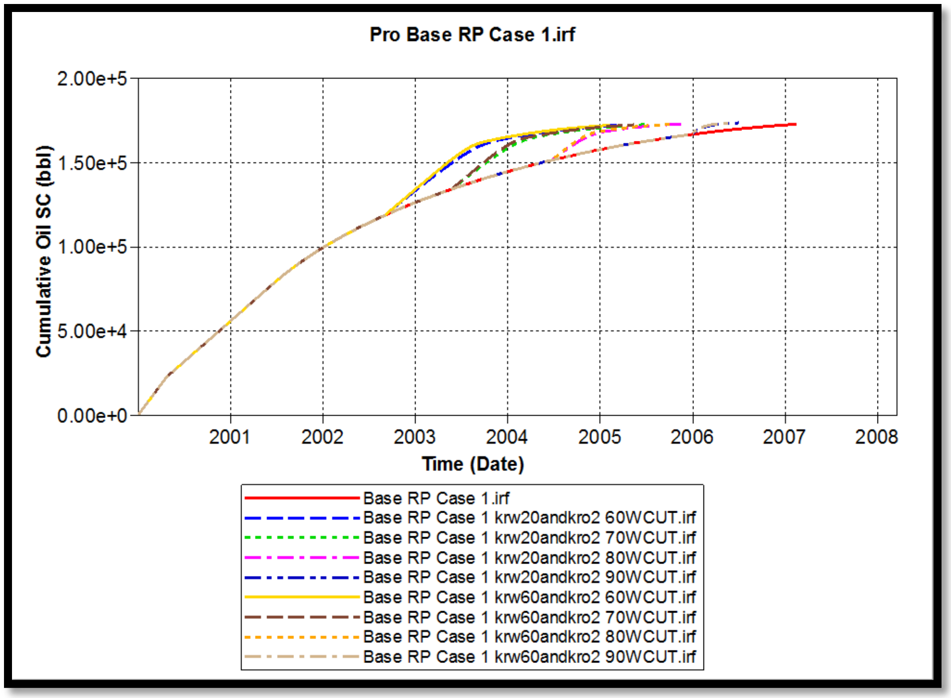


Figure 3.21 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 1).

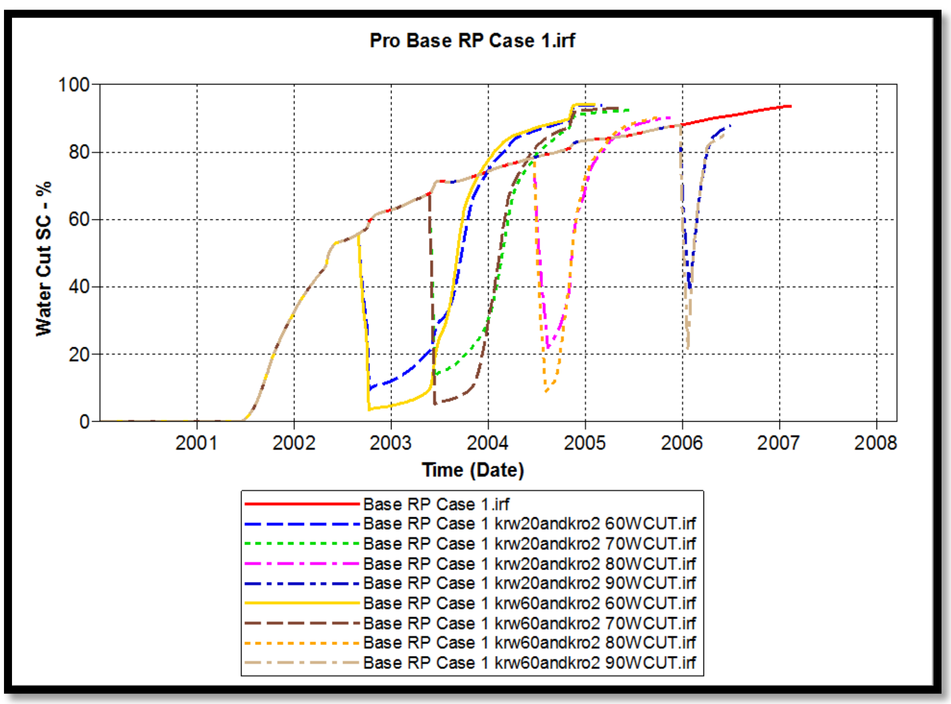


Figure 3.22 Water Cut (Case 1).

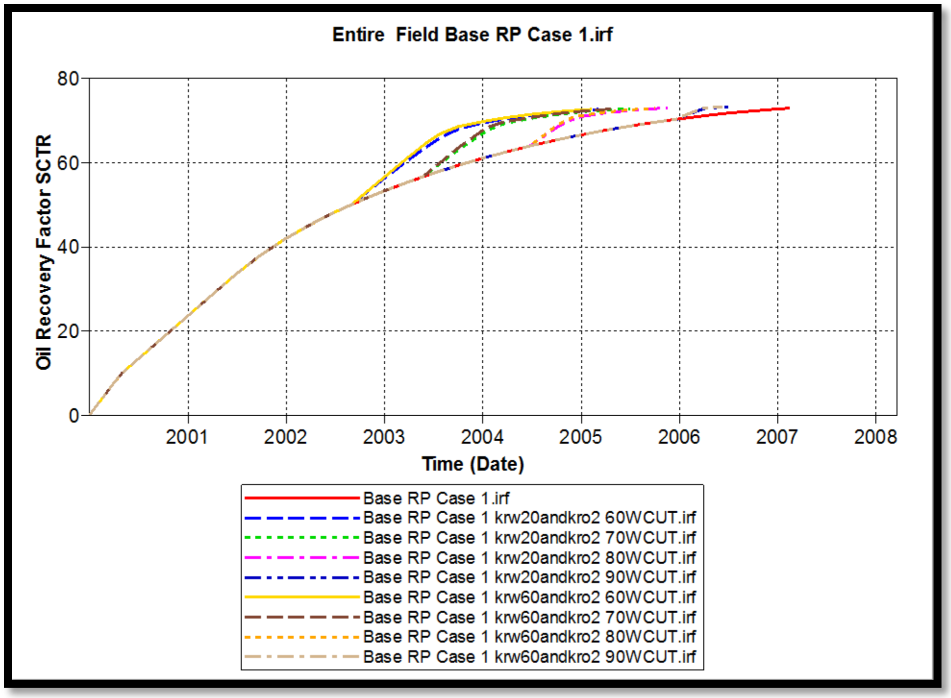


Figure 3.23 Oil Recovery Factor (Case 1).

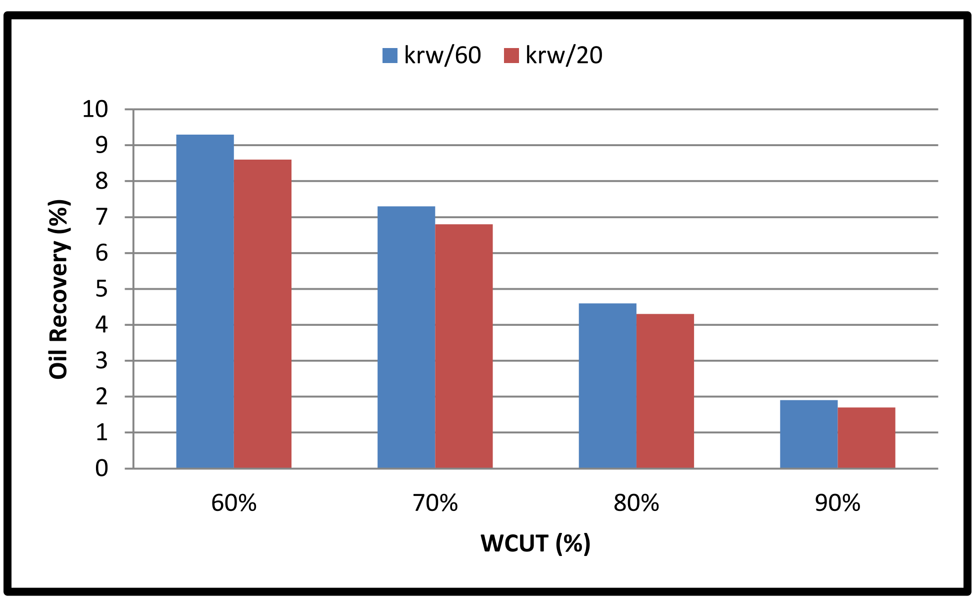


Figure 3.24 Compare The Results During Effective Period Case 1.

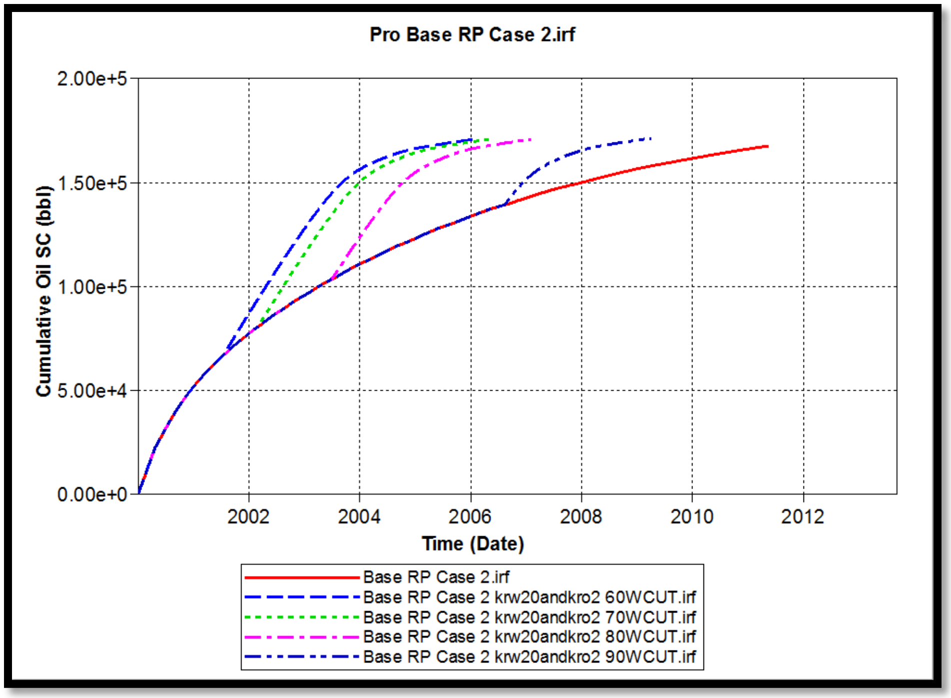


Figure 3.25 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 2 Scenario1).

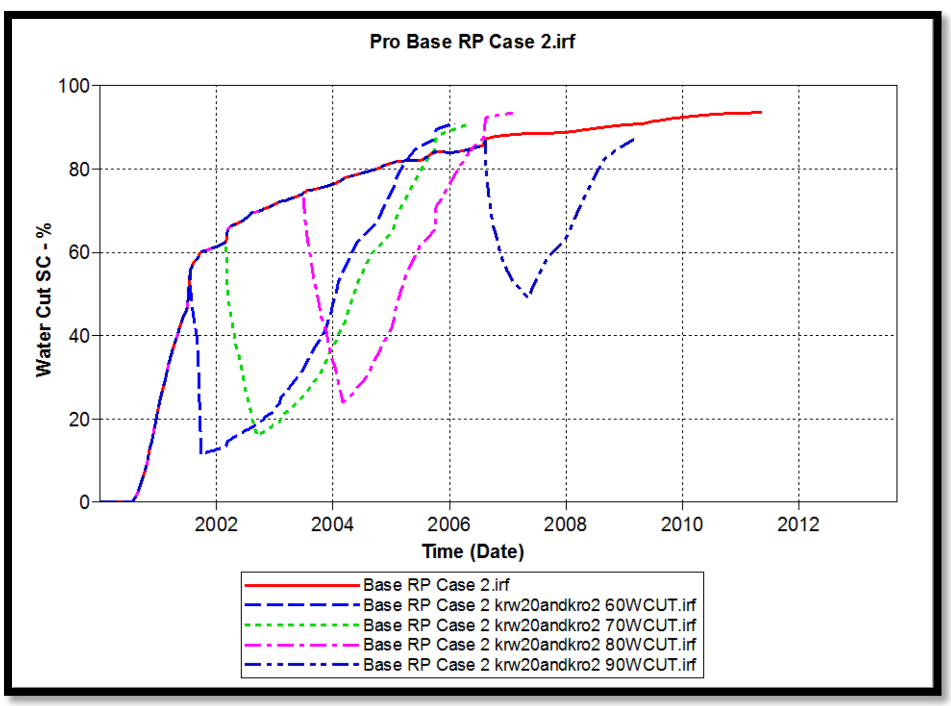


Figure 3.26 Water Cut (Case 2 Scenario 1).

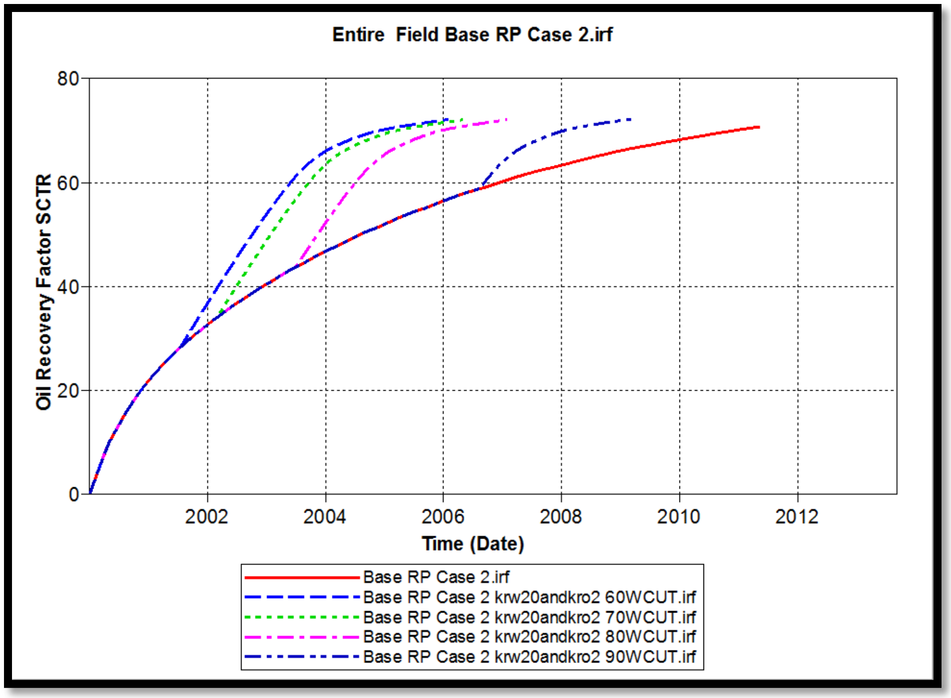


Figure 3.27 Oil Recovery Factor (Case 2 Scenario 1).

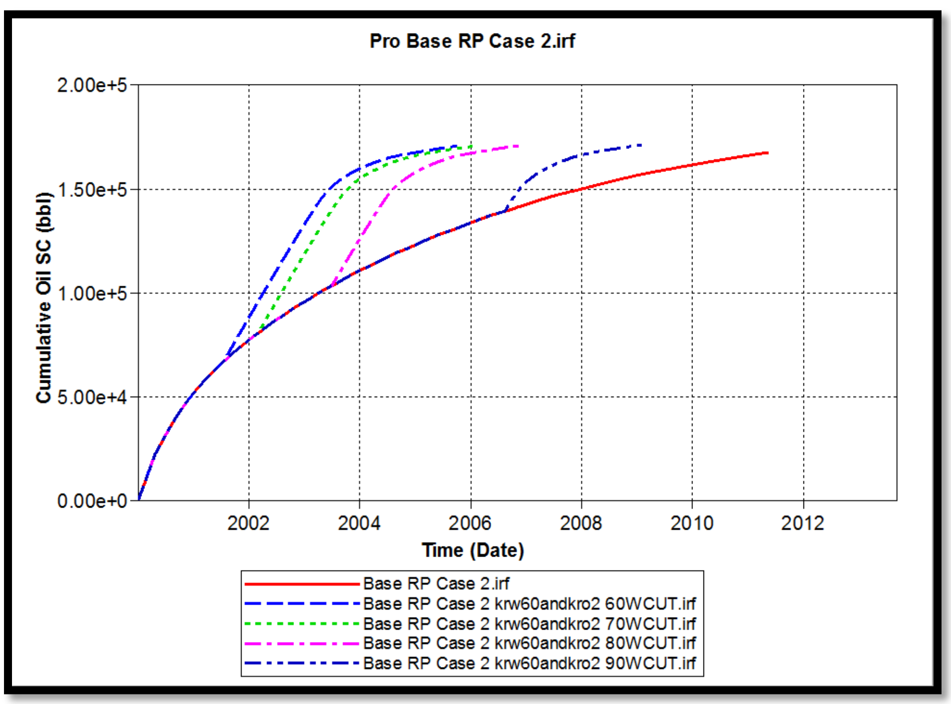


Figure 3.28 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 1 Scenario2).

Table 3.4 Effect on Accumulative Production and Oil Recovery (Case 1).

| RPM | DATE | Cumulative Oil SC at Base Case (STB) | Cumulative Oil SC at RPM (STB) | Oil Recovery Factor (%) | Oil Recovery Factor at Base Case (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|
| Base case 1 | 2/15/2007 | 172281 | 172281 | 72.9948 | | |
| krw/20 , kro/2 60% WCUT | 3/6/2005 | 159759 | 172267 | 72.7121 | 67.43 | 7.8 |
| krw/20 , kro/2 70% WCUT | 7/1/2005 | 162827 | 172752 | 72.9168 | 68.73 | 6.1 |
| krw/20 , kro/2 80% WCUT | 11/16/2005 | 166035 | 173098 | 73.9168 | 70.08 | 4.3 |
| krw/20 , kro/2 90% WCUT | 7/1/2006 | 170114 | 173742 | 73.3347 | 71.8 | 2.1 |
| krw/60 , kro/2 60% WCUT | 2/8/2005 | 158979 | 172292 | 72.7224 | 67.1 | 8.4 |
| krw/60 , kro/2 70% WCUT | 5/14/2005 | 161668 | 172612 | 72.8578 | 68.24 | 6.8 |
| krw/60 , kro/2 80% WCUT | 10/1/2005 | 165034 | 172954 | 73.0022 | 69.66 | 4.8 |
| krw/60 , kro/2 90% WCUT | 6/10/2006 | 169797 | 173775 | 73.3486 | 71.67 | 2.3 |

Table 3.5 Effect on Effective Period (days) and Corresponding Increased Oil Case 2 Scenario 1.

| RPM | Effective period (day) | RPM Radius (ft) | Volume of RPM ($ft^3$) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/20,kro/2 60% WCUT | 976 | 12.6 | 20 | 46524 | 92427 | 45903 | 19.4 |
| krw/20,kro/2 70% WCUT | 831 | 12.6 | 20 | 35972 | 77746 | 41774 | 17.6 |
| krw/20,kro/2 80% WCUT | 811 | 12.6 | 20 | 27236 | 60448 | 33212 | 14 |
| krw/20,kro/2 90% WCUT | 550 | 12.6 | 20 | 11580 | 26864 | 15284 | 6.5 |

Table 3.6 Effect on Effective Period (days) and Corresponding Increased Oil Case 2 Scenario 2.

| RPM | Effective period (day) | RPM Radius (ft) | Volume of RPM ($ft^3$) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/60,kro/2 60% WCUT | 837 | 12.6 | 20 | 41545 | 90513 | 48968 | 20.7 |
| krw/60,kro/2 70% WCUT | 746 | 12.6 | 20 | 32639 | 77594 | 44955 | 19 |
| krw/60,kro/2 80% WCUT | 655 | 12.6 | 20 | 23033 | 58152 | 35119 | 14.8 |
| krw/60,kro/2 90% WCUT | 498 | 12.6 | 20 | 10563 | 26965 | 16402 | 6.9 |

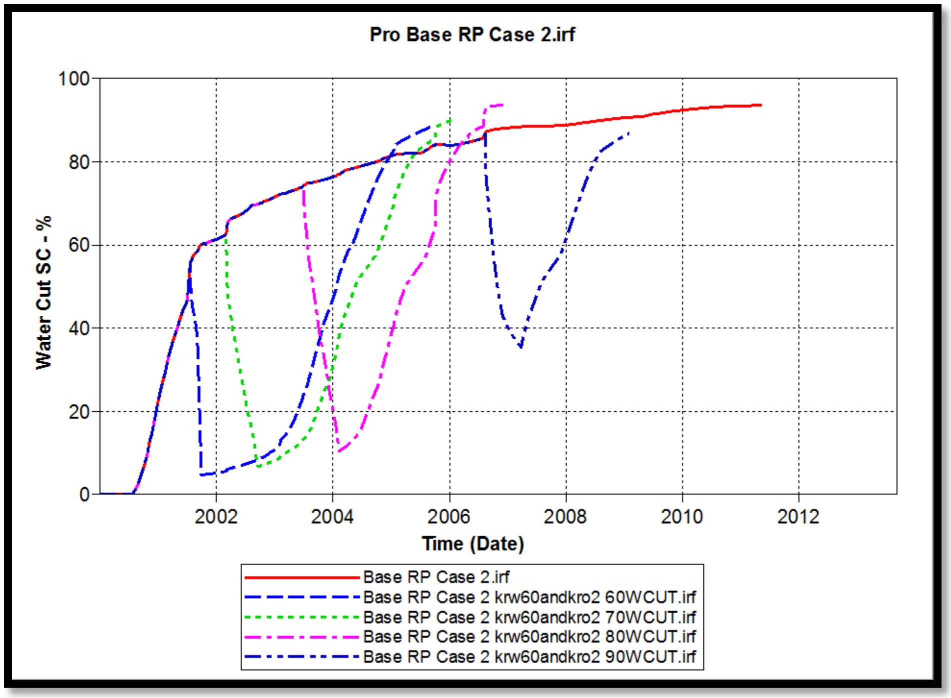


Figure 3.29 Water Cut (Case 2 Scenario 2).

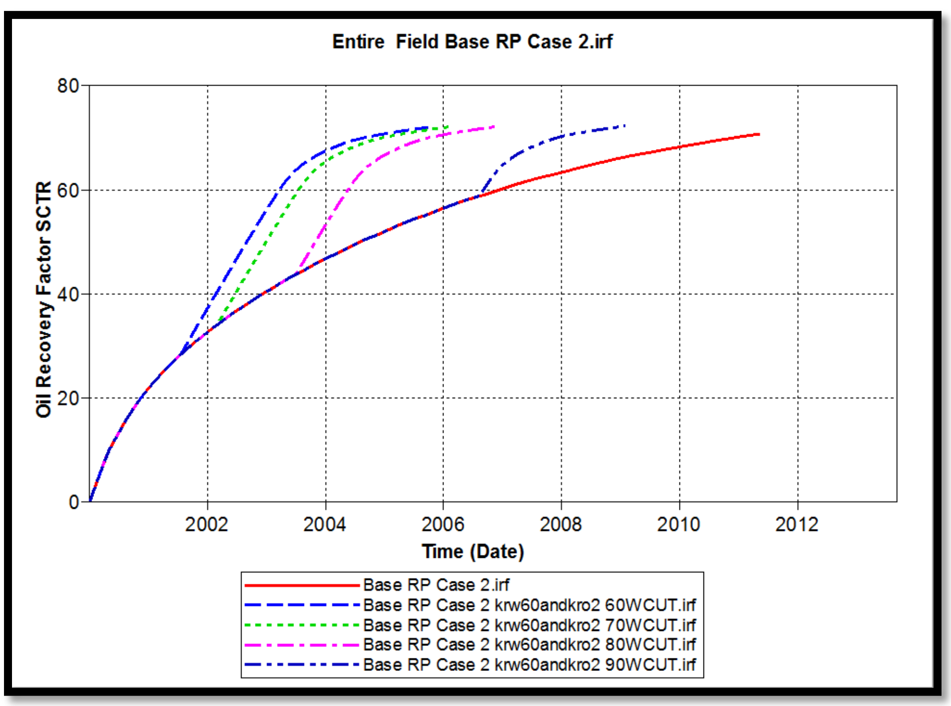


Figure 3.30 Oil Recovery Factor (Case 2 Scenario 2).

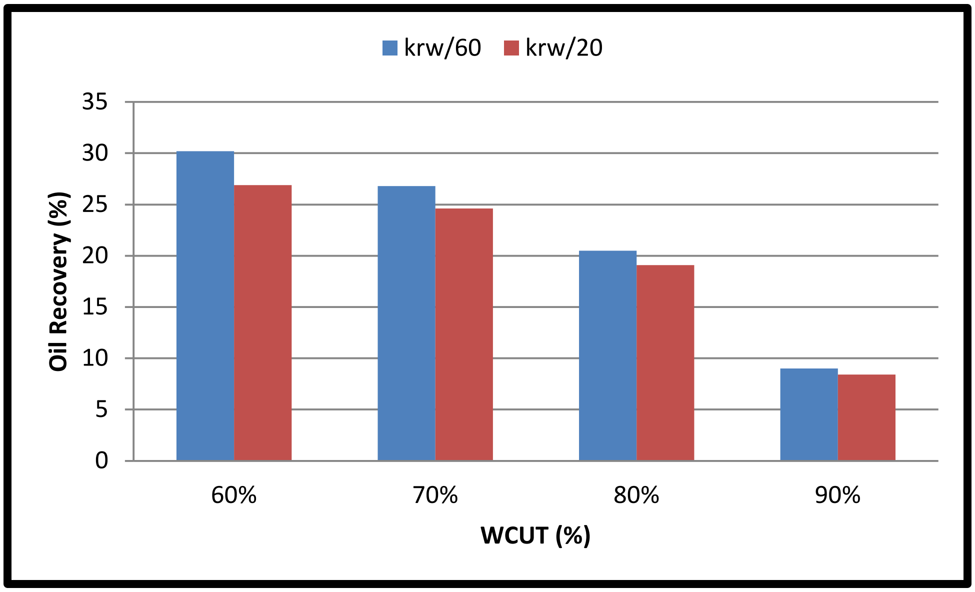


Figure 3.31 Comparison of Oil Recovery for Case 2.

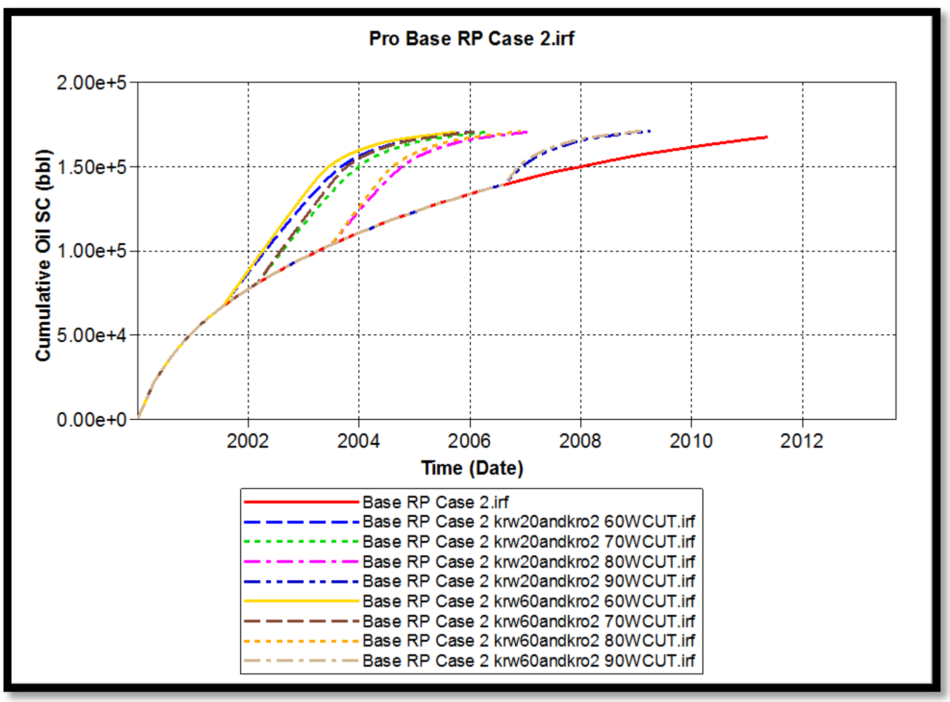


Figure 3.32 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 2).

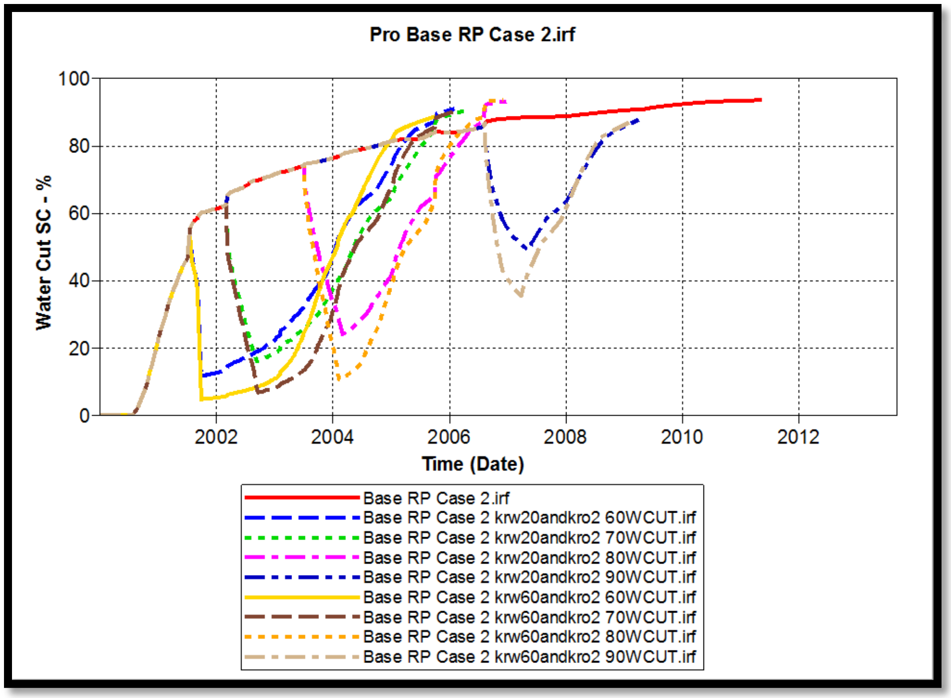


Figure 3.33 Water Cut (Case 2).

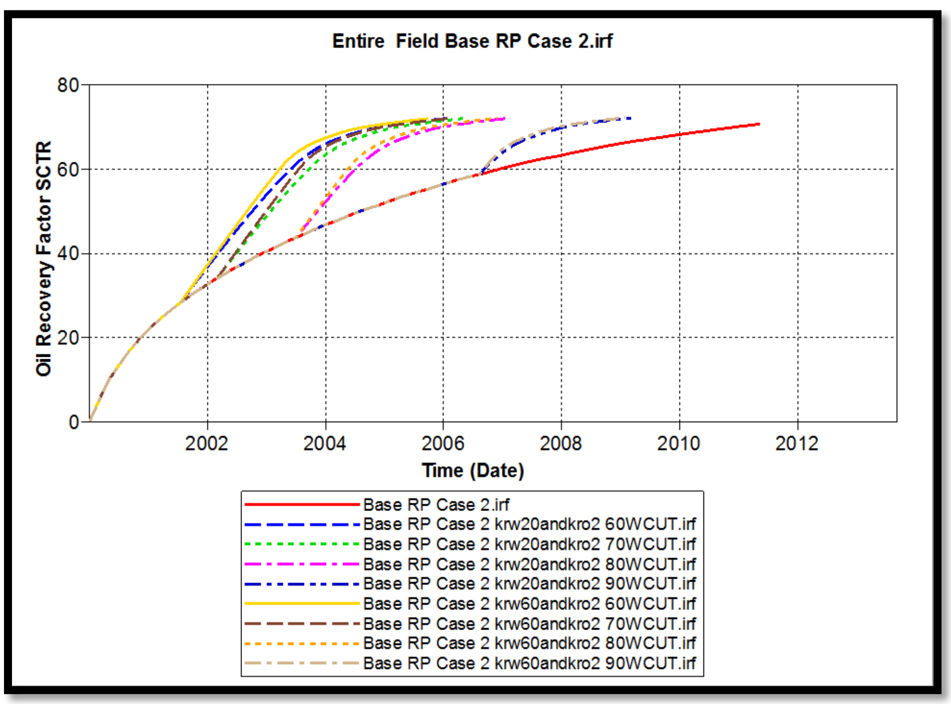


Figure 3.34 Oil Recovery Factor (Case 2).

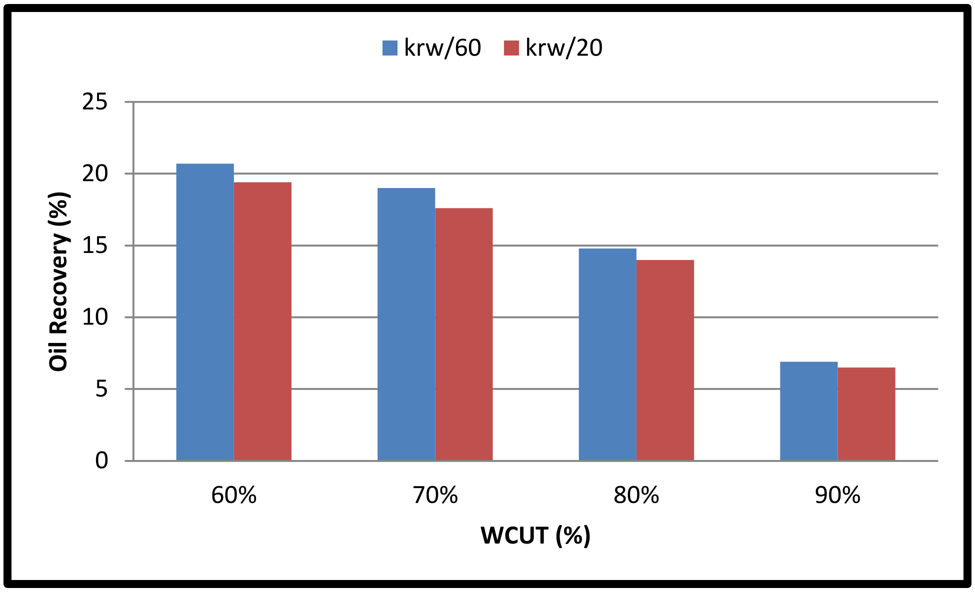


Figure 3.35 Compare The Results During Effective Period Case 2.

Table 3.7 Effect on Accumulative Production and Oil Recovery (Case 2).

| RPM | DATE | Cumulative Oil SC at Base Case (STB) | Cumulative Oil SC at RPM (STB) | Oil Recovery Factor (%) | Oil Recovery Factor at Base Case (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|
| Base case 2 | 5/16/2011 | 167639 | | 70.763 | | |
| krw/20,kro/2 60% WCUT | 2/1/2006 | 134688 | 170909 | 72.1431 | 56.85 | 26.9 |
| krw/20,kro/2 70% WCUT | 5/1/2006 | 137050 | 170773 | 72.0859 | 57.85 | 24.6 |
| krw/20,kro/2 80% WCUT | 2/1/2007 | 143424 | 170827 | 72.1084 | 60.54 | 19.1 |
| krw/20,kro/2 90% WCUT | 4/1/2009 | 158041 | 171297 | 72.3071 | 66.71 | 8.4 |
| krw/60,kro/2 60% WCUT | 10/1/2005 | 131116 | 170694 | 72.0524 | 55.34 | 30.2 |
| krw/60,kro/2 70% WCUT | 2/1/2006 | 134688 | 170811 | 72.1018 | 56.85 | 26.8 |
| krw/60,kro/2 80% WCUT | 12/1/2006 | 141943 | 171039 | 72.198 | 59.91 | 20.5 |
| krw/60,kro/2 90% WCUT | 2/1/2009 | 157167 | 171241 | 72.2834 | 66.34 | 9 |

Table 3.8 Effect on Effective Period (days) and Corresponding Increased Oil Case 3 Scenario 1.

| RPM | Effective period (day) | RPM Radius (ft) | Volume of RPM ($ft^3$) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/20,kro/2 60% WCUT | 952 | 39.9, 56.43 | 375 | 39278 | 59819 | 20541 | 8.7 |
| krw/20,kro/2 70% WCUT | 779 | 39.9, 56.43 | 375 | 28436 | 47628 | 19192 | 8.1 |
| krw/20,kro/2 80% WCUT | 777 | 39.9, 56.43 | 375 | 22283 | 38932 | 16649 | 7.0 |
| krw/20,kro/2 90% WCUT | 405 | 39.9, 56.43 | 375 | 8127 | 16865 | 8738 | 3.7 |

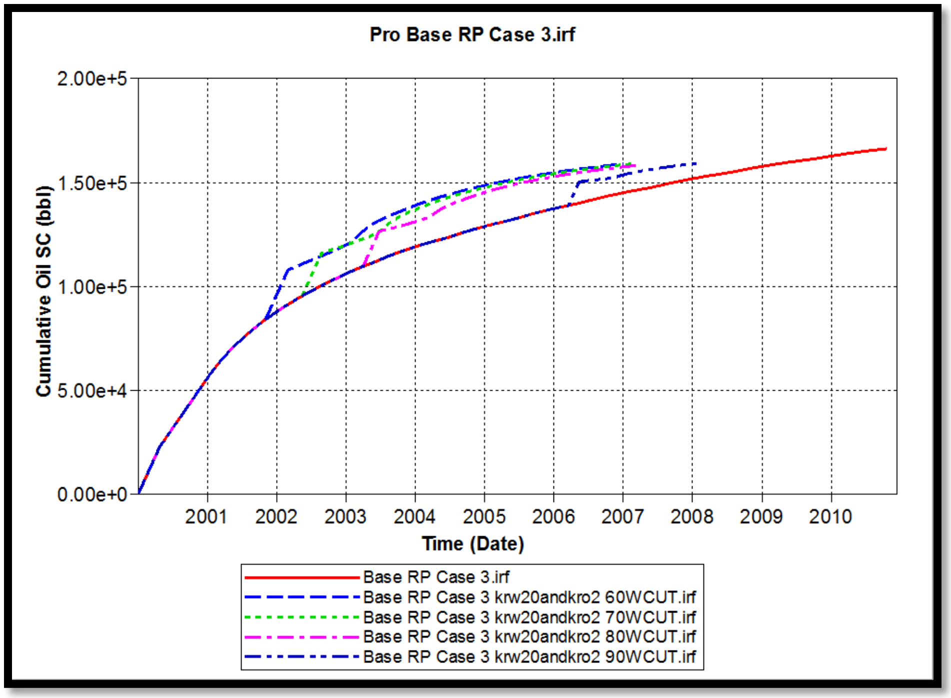


Figure 3.36 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 3 Scenario1).

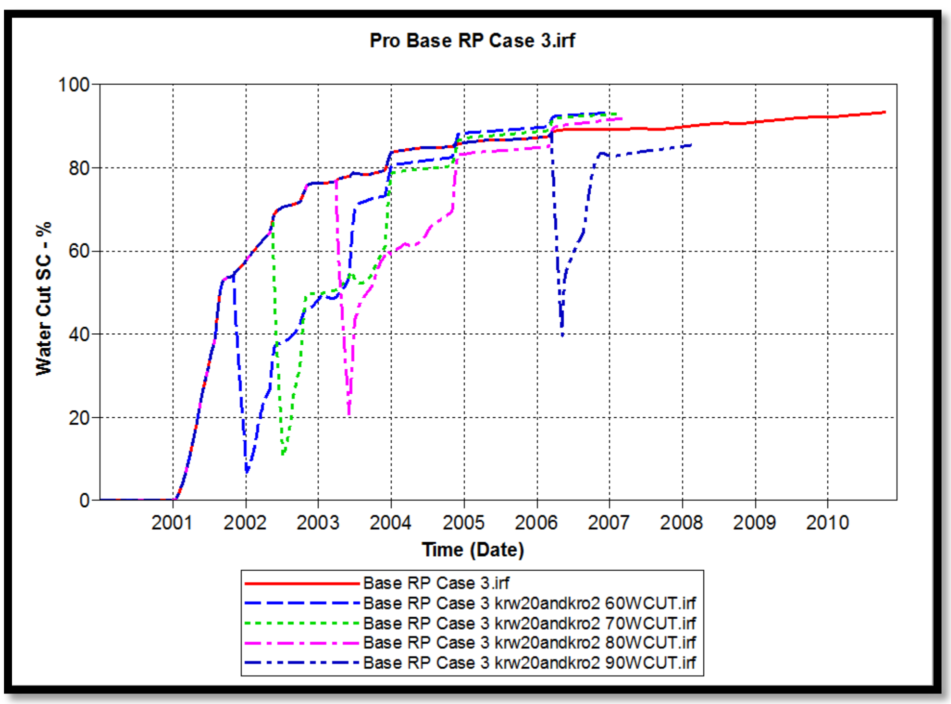


Figure 3.37 Water Cut (Case 3 Scenario 1).

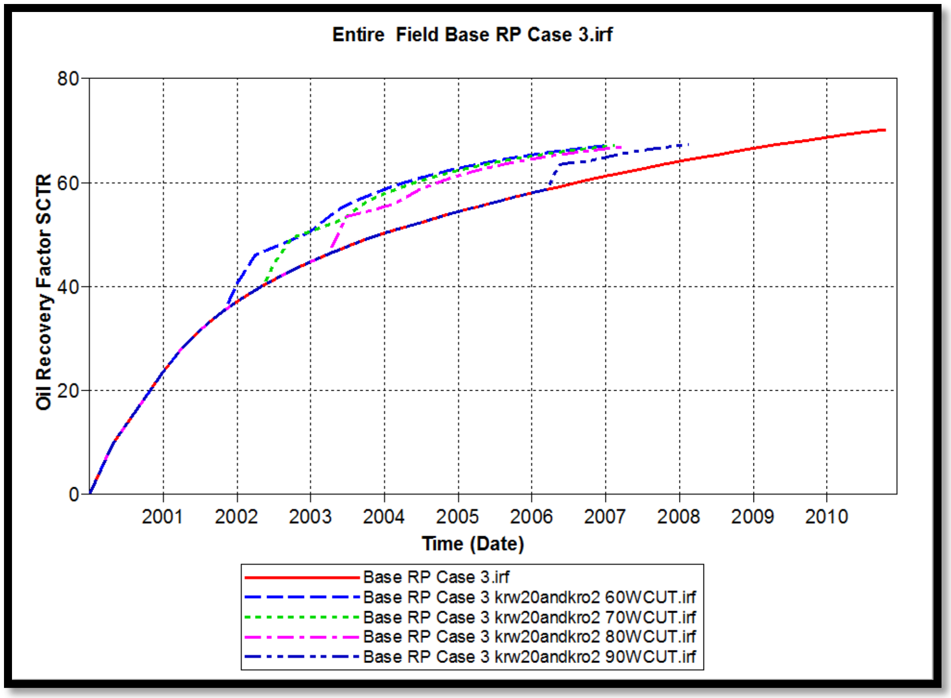


Figure 3.38 Oil Recovery Factor (Case 3 Scenario 1).

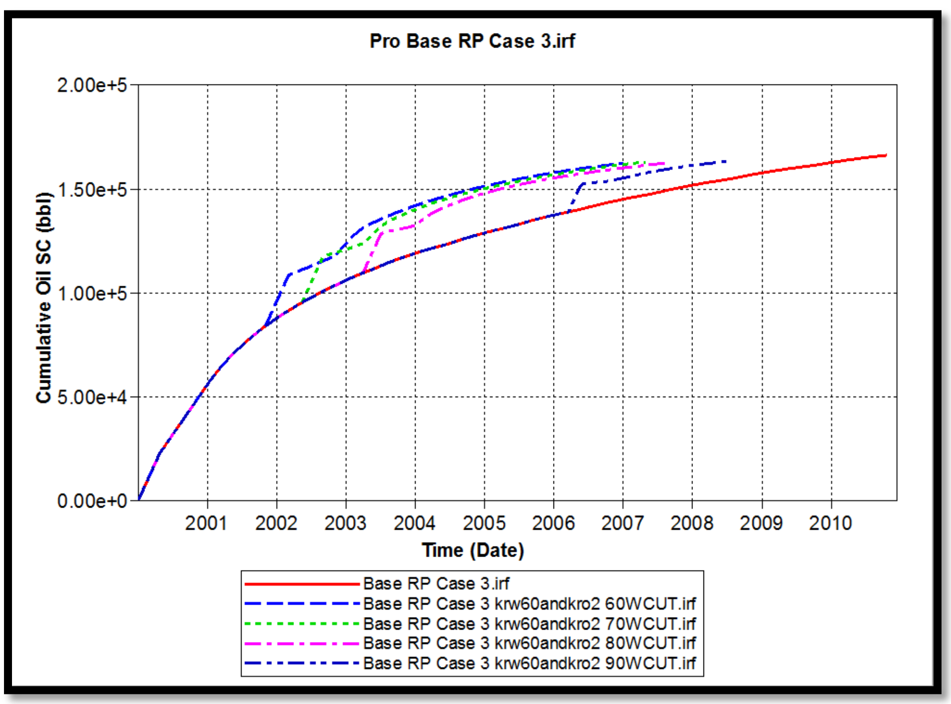


Figure 3.39 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 3 Scenario 2).

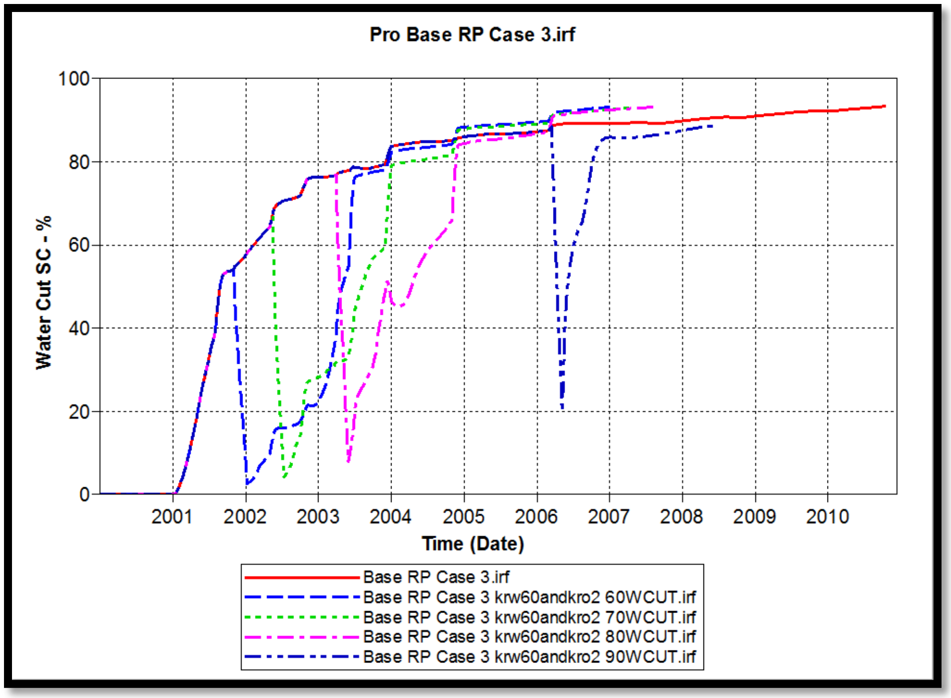


Figure 3.40 Water Cut (Case 3 Scenario 2).

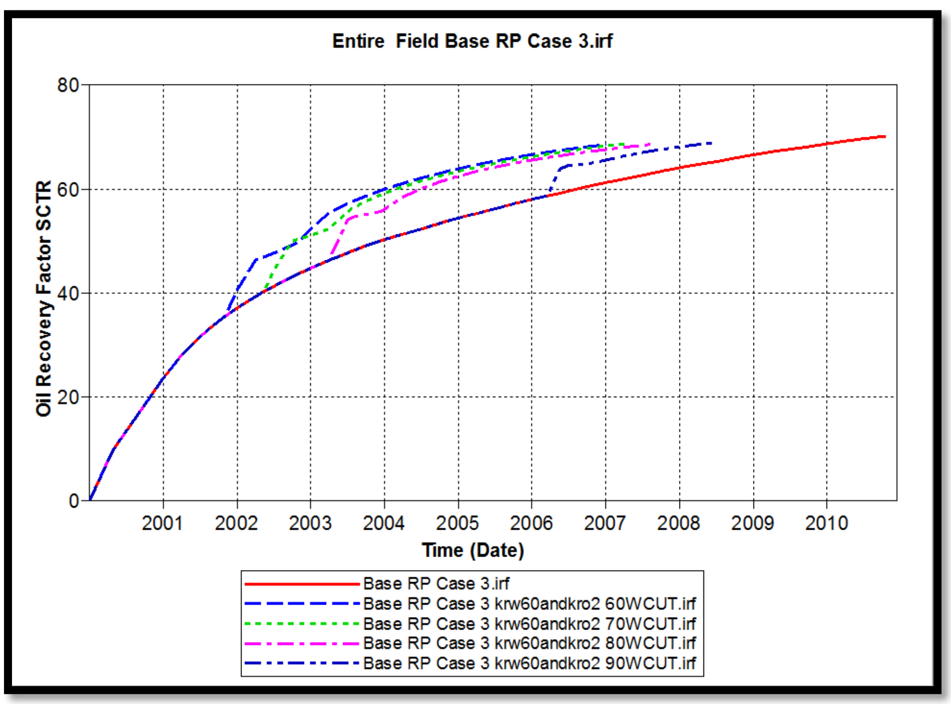


Figure 3.41 Oil Recovery Factor (Case 3 Scenario 2).

Table 3.9 Effect on Effective Period (days) and Corresponding Increased Oil Case 3 Scenario 2.

| RPM | Effective period (day) | RPM Radius (ft) | Volume of RPM ($ft^3$) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/60,kro/2 60% WCUT | 951 | 39.9, 56.43 | 375 | 39236 | 62519 | 23283 | 9.8 |
| krw/60,kro/2 70% WCUT | 764 | 39.9, 56.43 | 375 | 28057 | 50005 | 21948 | 9.3 |
| krw/60,kro/2 80% WCUT | 760 | 39.9, 56.43 | 375 | 21916 | 41117 | 19201 | 8.1 |
| krw/60,kro/2 90% WCUT | 440 | 39.9, 56.43 | 375 | 8749 | 19311 | 10562 | 4.5 |

Table 3.10 Effect on Accumulative Production and Oil Recovery (Case 3).

| RPM | DATE | Cumulative Oil SC at Base Case (STB) | Cumulative Oil SC at RPM (STB) | Oil Recovery Factor (%) | Oil Recovery Factor at Base Case (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|
| Base case 3 | 10/20/2010 | 166315 | | 70.1998 | | |
| krw/20 , kro/2 60% WCUT | 1/1/2007 | 145165 | 159033 | 67.1261 | 61.27 | 9.6 |
| krw/20 , kro/2 70% WCUT | 2/15/2007 | 145971 | 159083 | 67.1471 | 61.61 | 9 |
| krw/20 , kro/2 80% WCUT | 4/1/2007 | 146733 | 158463 | 66.8853 | 61.93 | 8 |
| krw/20 , kro/2 90% WCUT | 2/15/2008 | 152669 | 159461 | 67.3067 | 64.44 | 4.4 |
| krw/60 , kro/2 60% WCUT | 1/1/2007 | 145165 | 162390 | 68.5429 | 61.27 | 11.9 |
| krw/60 , kro/2 70% WCUT | 4/28/2007 | 147198 | 163055 | 68.8235 | 62.13 | 10.8 |
| krw/60 , kro/2 80% WCUT | 9/2/2007 | 149701 | 162752 | 68.6959 | 63.19 | 8.7 |
| krw/60 , kro/2 90% WCUT | 7/1/2008 | 154689 | 163306 | 68.9295 | 65.29 | 5.6 |

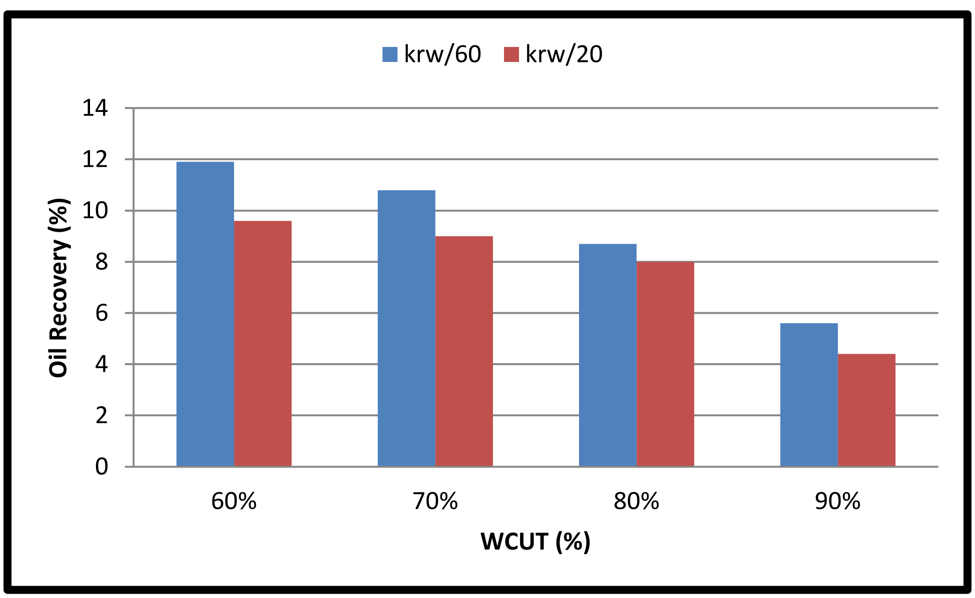


Figure 3.42 Comparison of Oil Recovery for Case 3.

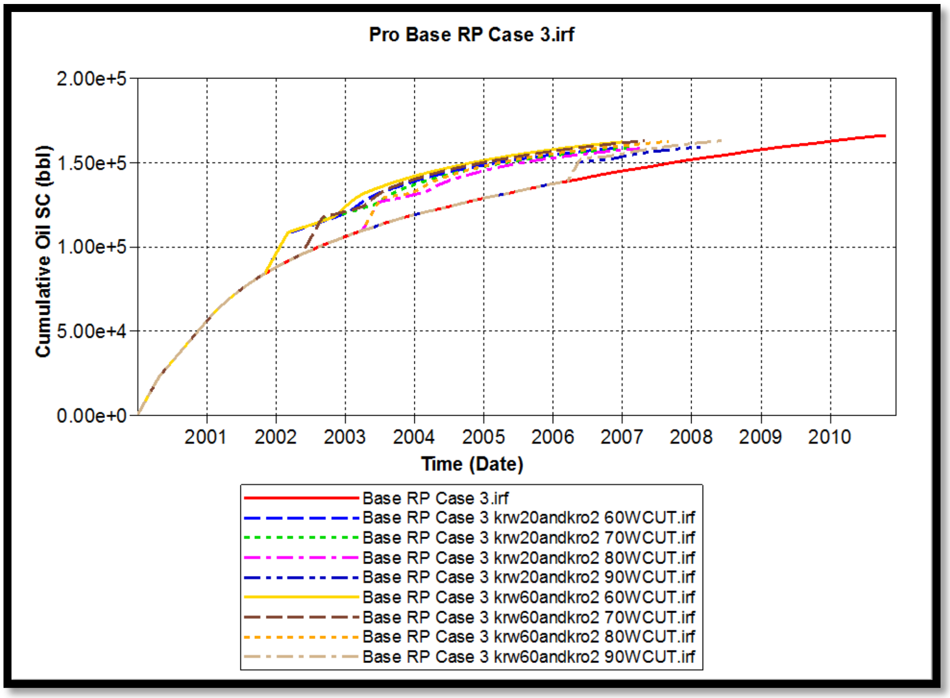


Figure 3.43 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 3).

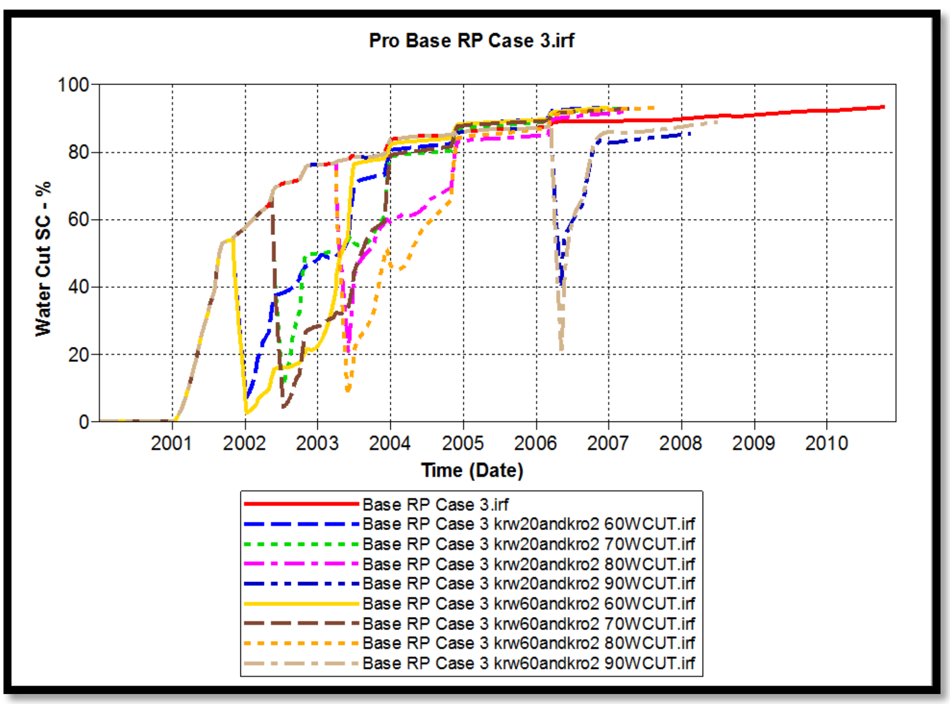


Figure 3.44 Water Cut (Case 3).

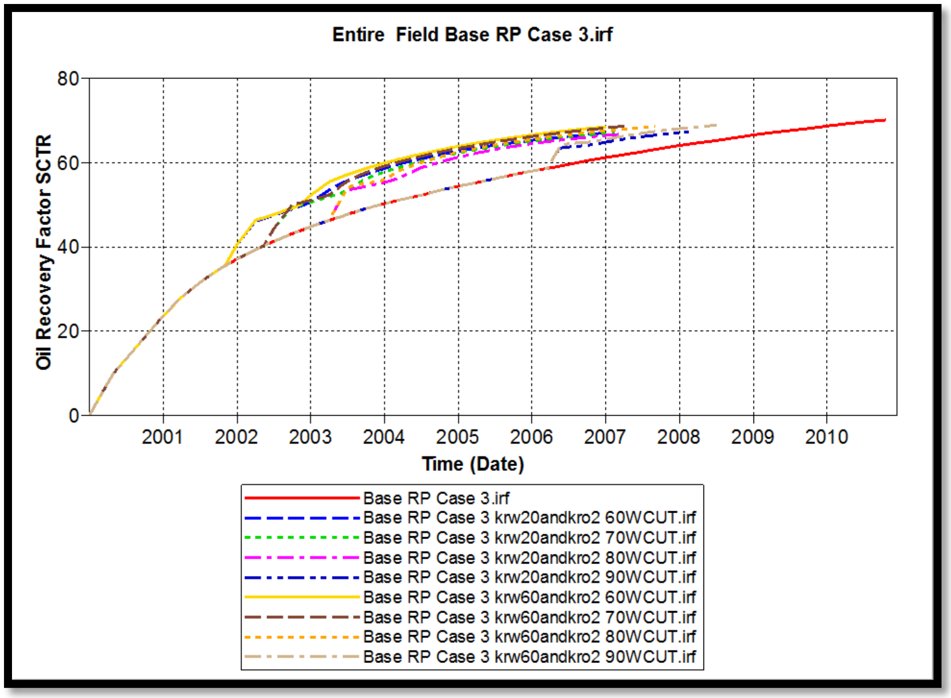


Figure 3.45 Oil Recovery Factor (Case 3).

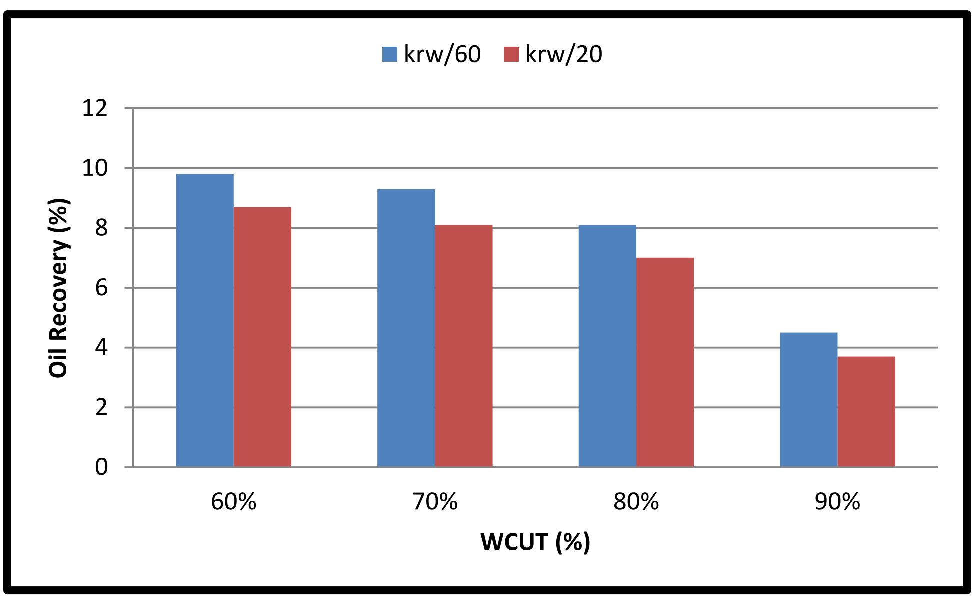


Figure 3.46 Compare The Results During Effective Period Case 3.

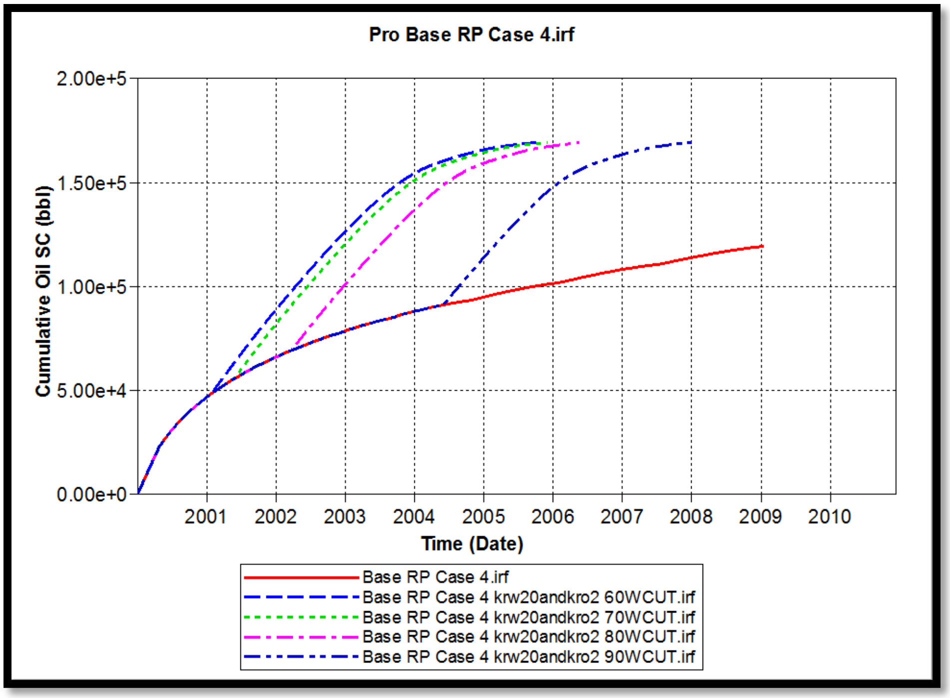


Figure 3.47 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 4 Scenario 1).

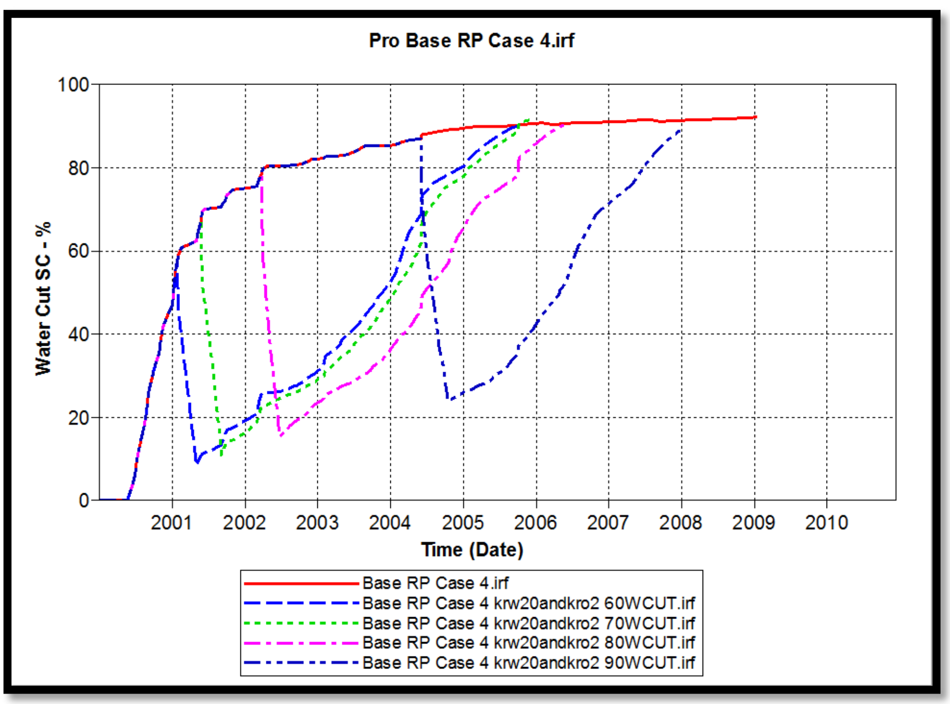


Figure 3.48 Water Cut (Case 4 Scenario 1).

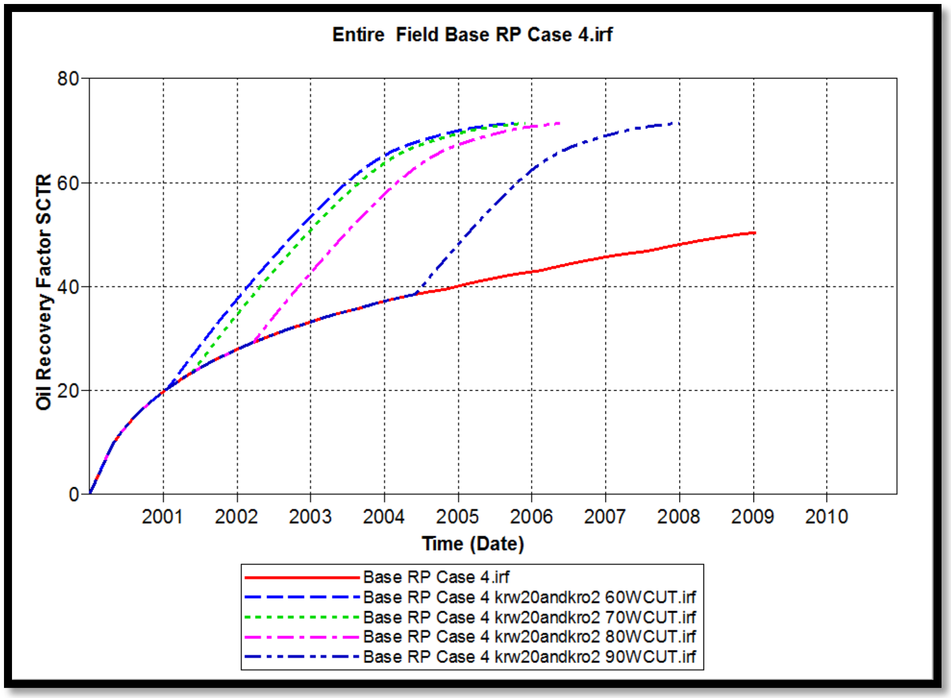


Figure 3.49 Oil Recovery Factor (Case 4 Scenario 1).

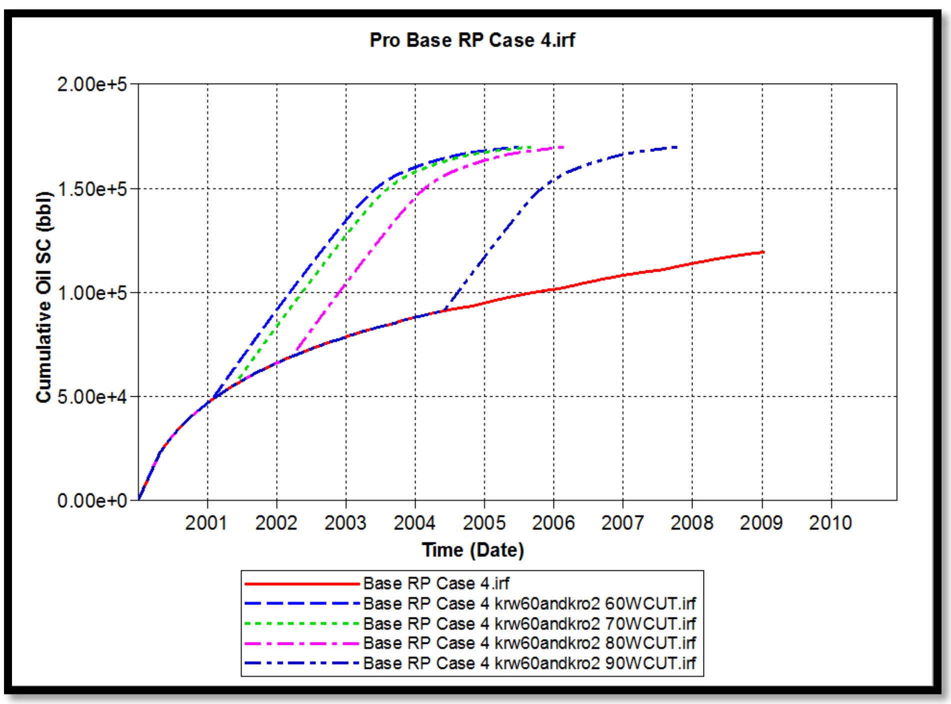


Figure 3.50 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 4 Scenario 2).

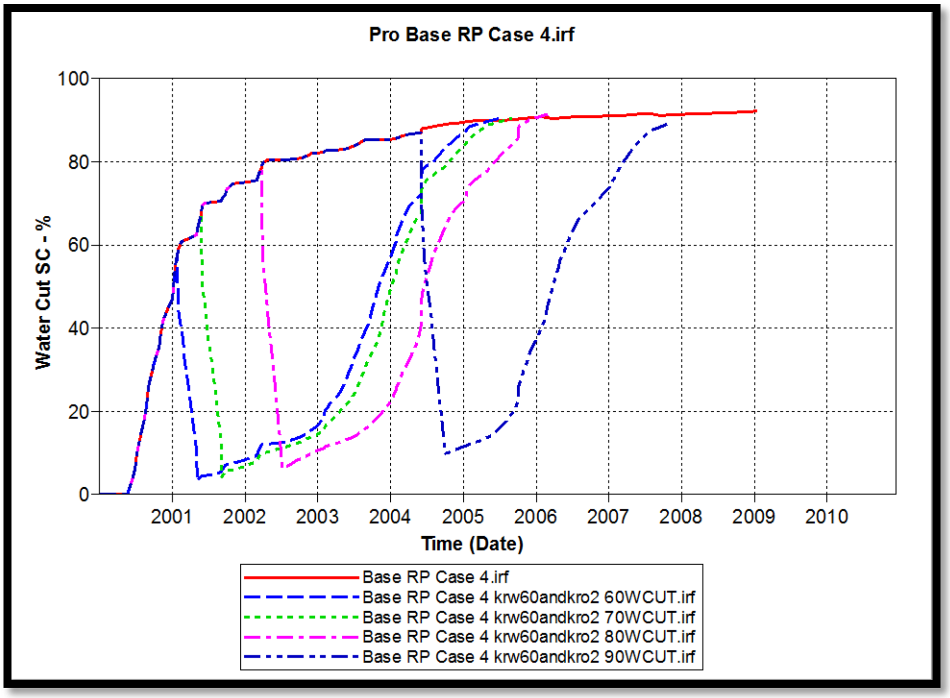


Figure 3.51 Water Cut (Case 4 Scenario 2).

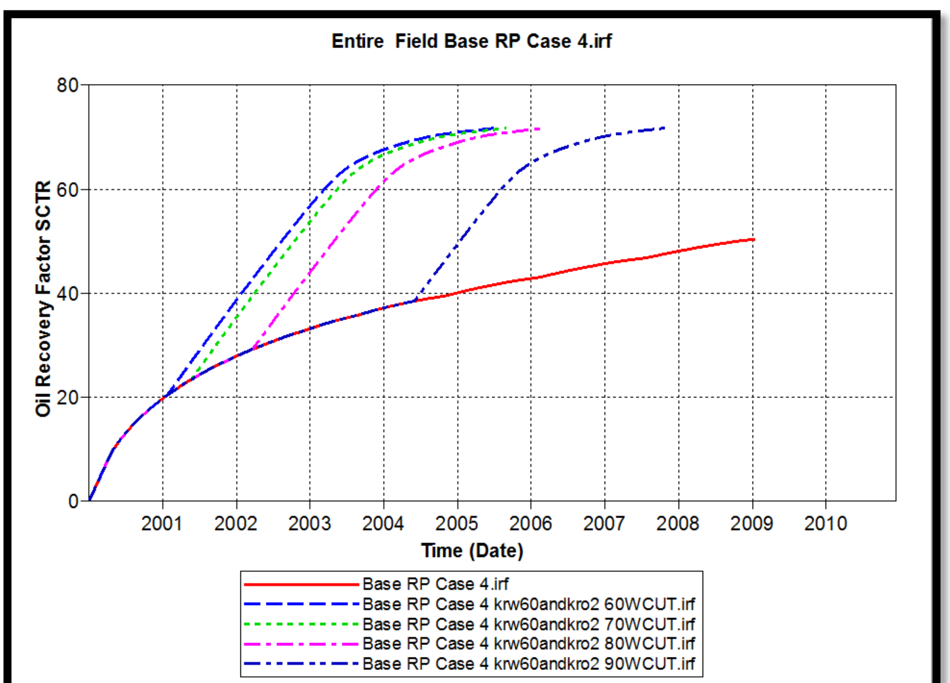


Figure 3.52 Oil Recovery Factor (Case 4 Scenario 2).

Table 3.11 Effect on Effective Period (days) and Corresponding Increased Oil Case 4 Scenario 1.

| RPM | Effective period (day) | RPM Radius (ft) | Volume of RPM ($ft^3$) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improve ment (%) |
|---|---|---|---|---|---|---|---|
| krw/20,kro/2 60% WCUT | 1406 | 12.6, 25.2 | 50 | 45748 | 116702 | 70954 | 29.9 |
| krw/20,kro/2 70% WCUT | 1287 | 12.6, 25.2 | 50 | 38628 | 108152 | 69524 | 29.3 |
| krw/20,kro/2 80% WCUT | 1365 | 12.6, 25.2 | 50 | 32006 | 98187 | 66181 | 27.9 |
| krw/20,kro/2 90% WCUT | 1141 | 12.6, 25.2 | 50 | 19577 | 76317 | 56740 | 23.9 |

Table 3.12 Effect on Effective Period (days) and Corresponding Increased Oil Case 4 Scenario 2.

| RPM | Effective period (day) | RPM Radius (ft) | Volume of RPM ($ft^3$) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/60,kro/2 60% WCUT | 1361 | 12.6, 25.2 | 50 | 44878 | 118709 | 73832 | 31.2 |
| krw/60,kro/2 70% WCUT | 1257 | 12.6, 25.2 | 50 | 37950 | 110814 | 72864 | 30.8 |
| krw/60,kro/2 80% WCUT | 1106 | 12.6, 25.2 | 50 | 27620 | 96348 | 68727 | 29 |
| krw/60,kro/2 90% WCUT | 1003 | 12.6, 25.2 | 50 | 17940 | 76112 | 58172 | 24.6 |

Table 3.13 Effect on Accumulative Production and Oil Recovery (Case 4).

| RPM | DATE | Cumulative Oil SC at Base Case (STB) | Cumulative Oil SC at RPM (STB) | Oil Recovery Factor (%) | Oil Recovery Factor at Base Case (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|
| Base case 4 | 1/16/2009 | 119431 | | 50.4136 | | |
| krw/20 , kro/2 60% WCUT | 10/1/2005 | 100267 | 169304 | 71.4655 | 42.32 | 68.9 |
| krw/20 , kro/2 70% WCUT | 12/1/2005 | 101155 | 169316 | 71.4708 | 42.7 | 67.4 |
| krw/20 , kro/2 80% WCUT | 5/20/2006 | 104152 | 169191 | 71.4181 | 43.96 | 62.4 |
| krw/20 , kro/2 90% WCUT | 1/1/2008 | 113955 | 169359 | 71.4888 | 48.1 | 48.6 |
| krw/60 , kro/2 60% WCUT | 7/1/2005 | 98696.6 | 169960 | 71.7424 | 41.66 | 72.2 |
| krw/60 , kro/2 70% WCUT | 9/1/2005 | 99784.8 | 169973 | 71.7481 | 42.12 | 70.3 |
| krw/60 , kro/2 80% WCUT | 3/1/2006 | 102421 | 169890 | 71.713 | 43.23 | 65.9 |
| krw/60 , kro/2 90% WCUT | 11/1/2007 | 112850 | 170034 | 71.7739 | 47.63 | 50.7 |

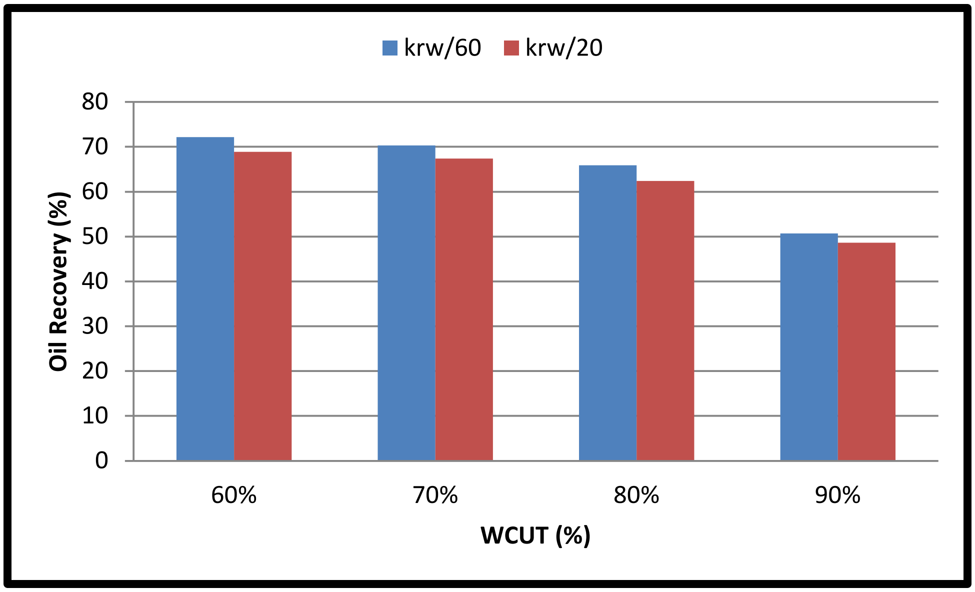


Figure 3.53 Comparison of Oil Recovery for Case 4.

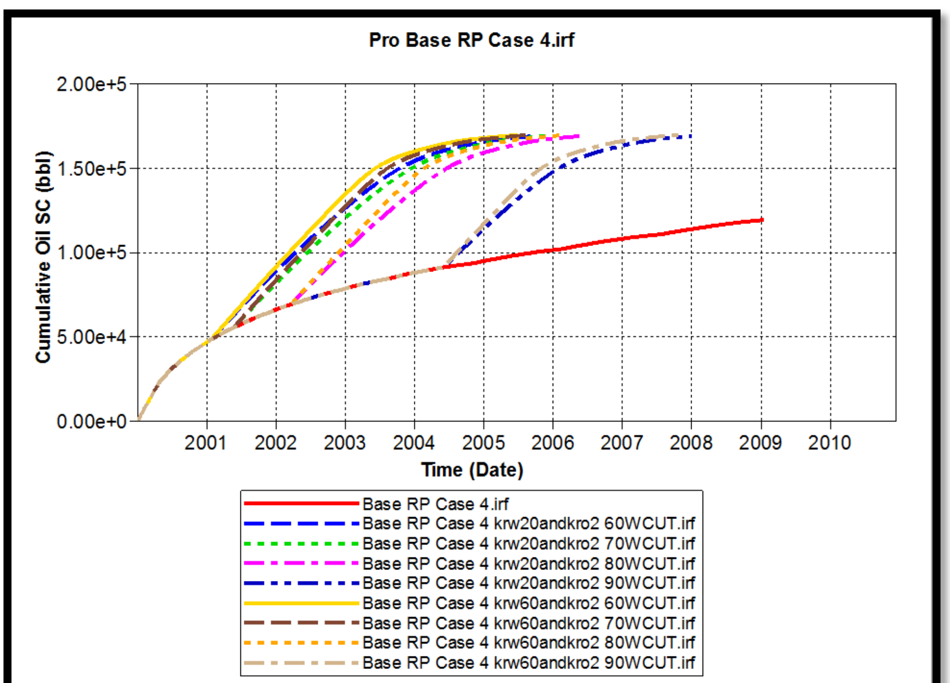


Figure 3.54 Cumulative Oil at Different Disproportionate Permeability Reduction (Case 4).

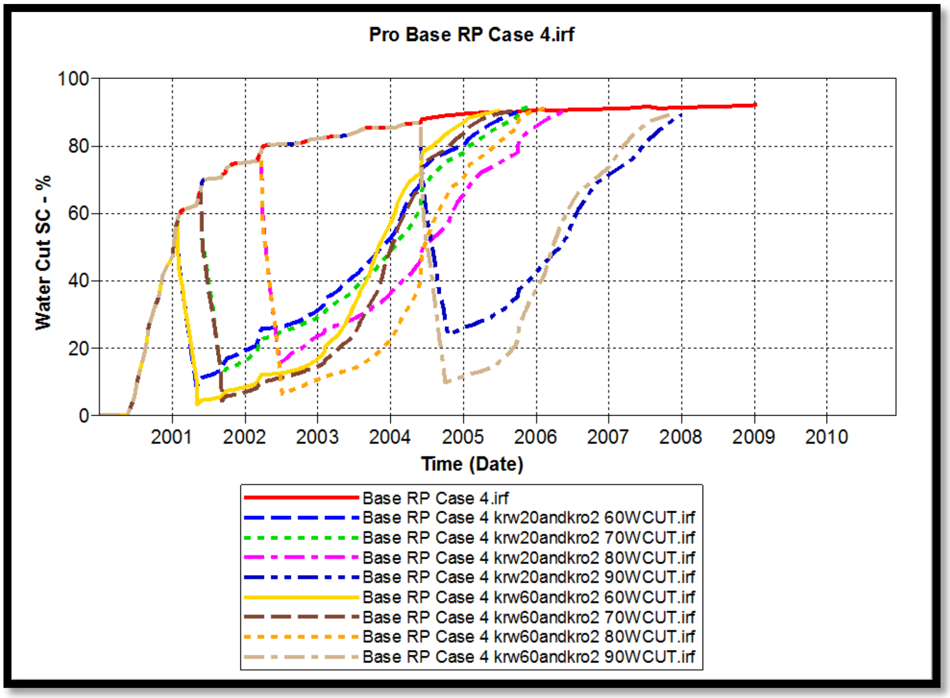


Figure 3.55 Water Cut (Case 4).

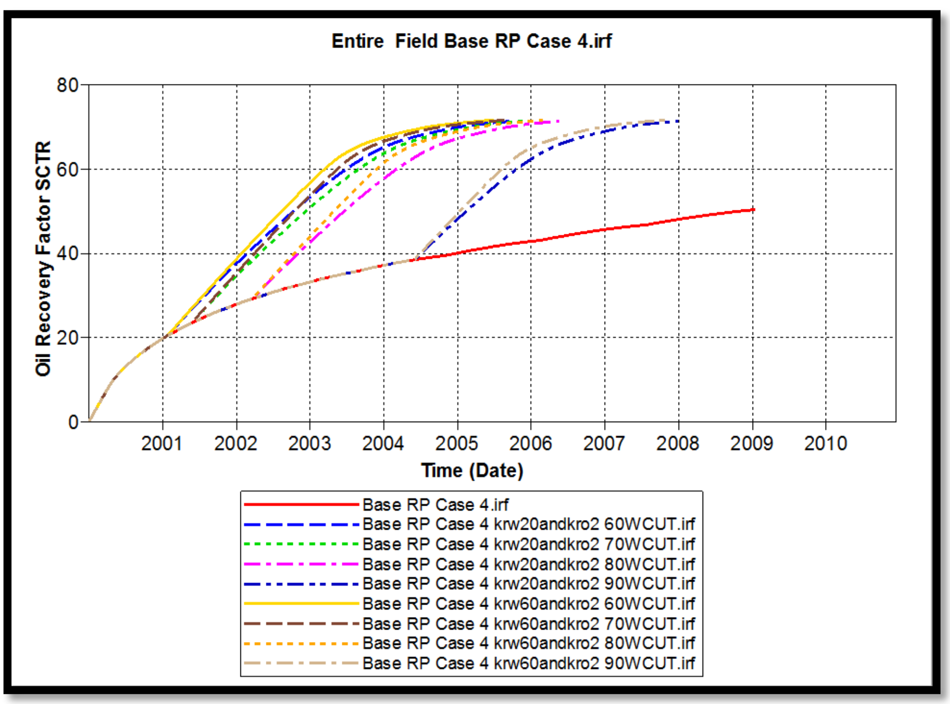


Figure 3.56 Oil Recovery Factor (Case 4).

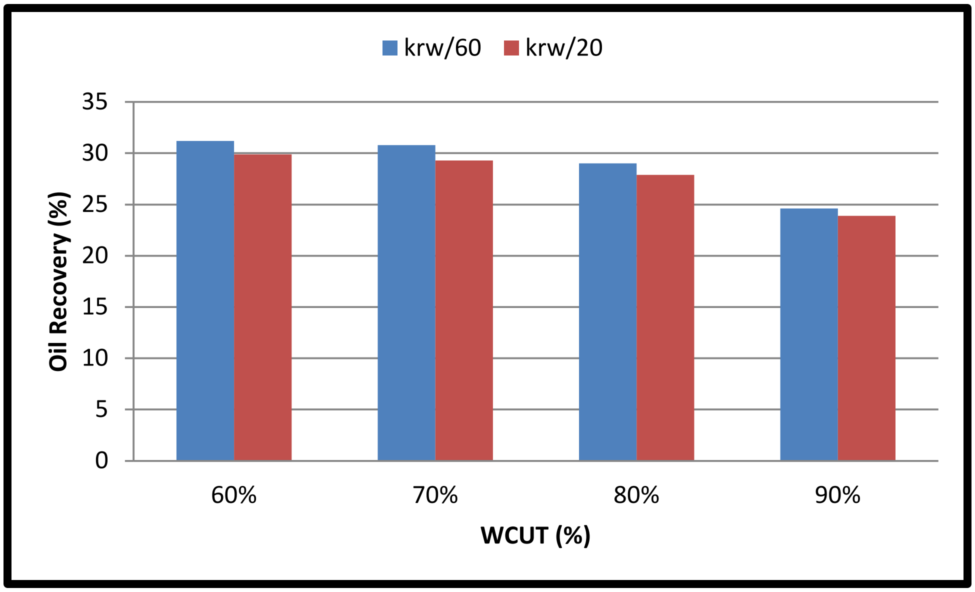


Figure 3.57 Compare The Results During Effective Period Case 4.

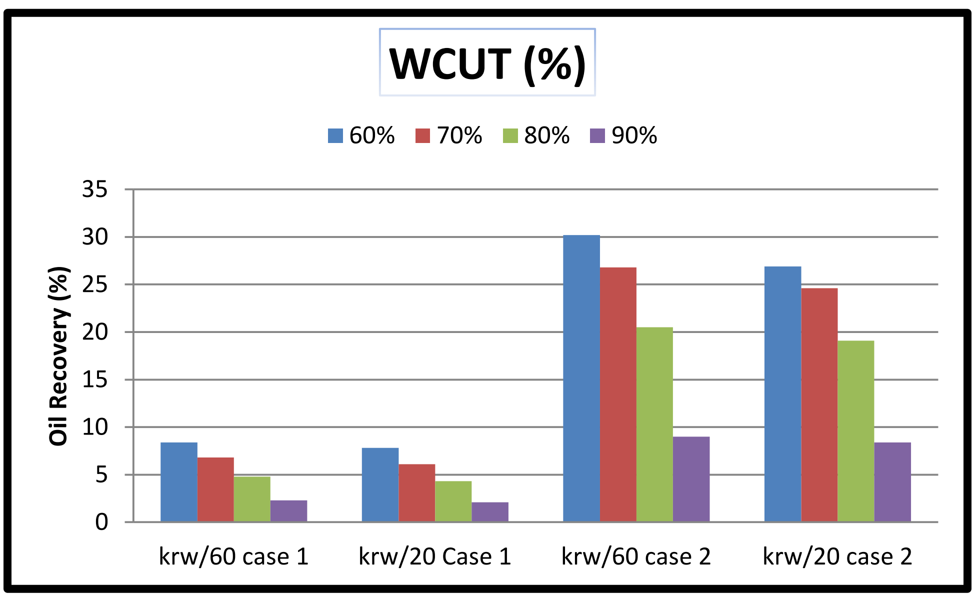


Figure 3.58 Comparison of Oil Recovery for Case 1 and Case 2.

Table 3.14 Effect on Accumulative Production and Oil Recovery: Case 1 and Case 2.

| RPM | DATE | Cumulative Oil SC at Base Case (STB) | Cumulative Oil SC at RPM (STB) | Oil Recovery Factor (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|
| **Linear Flow one layer** | | | | | |
| Base case 1 | 2/15/2007 | 172281 | | 72.9948 | |
| krw/20,kro/2 60% WCUT | 3/6/2005 | 159759 | 172267 | 72.7121 | 7.8 |
| krw/20,kro/2 70%WCUT | 7/1/2005 | 162827 | 172752 | 72.9168 | 6.1 |
| krw/20,kro/2 80% WCUT | 11/16/2005 | 166035 | 173098 | 73.9168 | 4.3 |
| krw/20,kro/2 90% WCUT | 7/1/2006 | 170114 | 173742 | 73.3347 | 2.1 |
| krw/60,kro/2 60% WCUT | 2/8/2005 | 158979 | 172292 | 72.7224 | 8.4 |
| krw/60,kro/2 70% WCUT | 5/14/2005 | 161668 | 172612 | 72.8578 | 6.8 |
| krw/60,kro/2 80% WCUT | 10/1/2005 | 165034 | 172954 | 73.0022 | 4.8 |
| krw/60,kro/2 90% WCUT | 6/10/2006 | 169797 | 173775 | 73.3486 | 2.3 |
| **Five spot one layer** | | | | | |
| Base case 2 | 5/16/2011 | 167639 | | 70.763 | |
| krw/20,kro/2 60% WCUT | 2/1/2006 | 134688 | 170909 | 72.1431 | 26.9 |
| krw/20,kro/2 70% WCUT | 5/1/2006 | 137050 | 170773 | 72.0859 | 24.6 |
| krw/20,kro/2 80% WCUT | 2/1/2007 | 143424 | 170827 | 72.1084 | 19.1 |
| krw/20,kro/2 90% WCUT | 4/1/2009 | 158041 | 171297 | 72.3071 | 8.4 |
| krw/60,kro/2 60% WCUT | 10/1/2005 | 131116 | 170694 | 72.0524 | 30.2 |
| krw/60,kro/2 70% WCUT | 2/1/2006 | 134688 | 170811 | 72.1018 | 26.8 |
| krw/60,kro/2 80% WCUT | 12/1/2006 | 141943 | 171039 | 72.198 | 20.5 |
| krw/60,kro/2 90% WCUT | 2/1/2009 | 157167 | 171241 | 72.2834 | 9.0 |

Table 3.15 Effect on Accumulative Production and Oil Recovery Case 3 and Case 4.

| RPM | DATE | Cumulative Oil SC at Base Case (STB) | Cumulative Oil SC at RPM (STB) | Oil Recovery Factor (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|
| **Linear flow two layers** | | | | | |
| Base case 3 | 10/20/2010 | 166315 | | 70.1998 | |
| krw/20,kro/2 60% WCUT | 1/1/2007 | 145165 | 159033 | 67.1261 | 9.6 |
| krw/20,kro/2 70% WCUT | 2/15/2007 | 145971 | 159083 | 67.1471 | 9.0 |
| krw/20,kro/2 80% WCUT | 4/1/2007 | 146733 | 158463 | 66.8853 | 8.0 |
| krw/20,kro/2 90% WCUT | 2/15/2008 | 152669 | 159461 | 67.3067 | 4.4 |
| krw/60,kro/2 60% WCUT | 1/1/2007 | 145165 | 162390 | 68.5429 | 11.9 |
| krw/60,kro/2 70% WCUT | 4/28/2007 | 147198 | 163055 | 68.8235 | 10.8 |
| krw/60,kro/2 80% WCUT | 9/2/2007 | 149701 | 162752 | 68.6959 | 8.7 |
| krw/60,kro/2 90% WCUT | 7/1/2008 | 154689 | 163306 | 68.9295 | 5.6 |
| **Five spot two layers** | | | | | |
| Base case 4 | 1/16/2009 | 119431 | | 50.4136 | |
| krw/20,kro/2 60% WCUT | 10/1/2005 | 100267 | 169304 | 71.4655 | 68.9 |
| krw/20,kro/2 70% WCUT | 12/1/2005 | 101155 | 169316 | 71.4708 | 67.4 |
| krw/20,kro/2 80% WCUT | 5/20/2006 | 104152 | 169191 | 71.4181 | 62.4 |
| krw/20,kro/2 90% WCUT | 1/1/2008 | 113955 | 169359 | 71.4888 | 48.6 |
| krw/60,kro/2 60% WCUT | 7/1/2005 | 98696.6 | 169960 | 71.7424 | 72.2 |
| krw/60,kro/2 70% WCUT | 9/1/2005 | 99784.8 | 169973 | 71.7481 | 70.3 |
| krw/60,kro/2 80% WCUT | 3/1/2006 | 102421 | 169890 | 71.713 | 65.9 |
| krw/60,kro/2 90% WCUT | 11/1/2007 | 112850 | 170034 | 71.7739 | 50.7 |

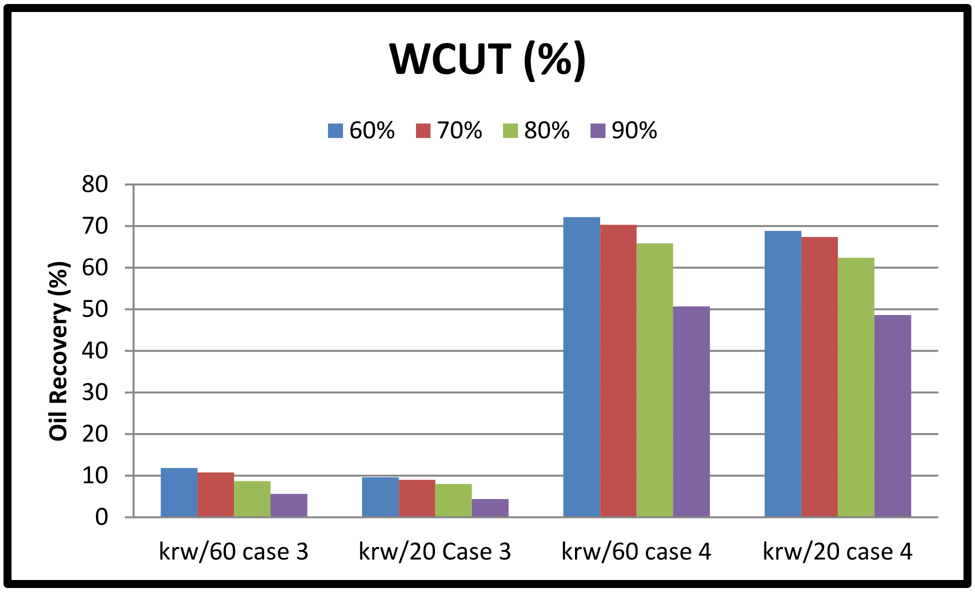


Figure 3.59 Comparison of Oil Recovery for Case 3 and Case 4.

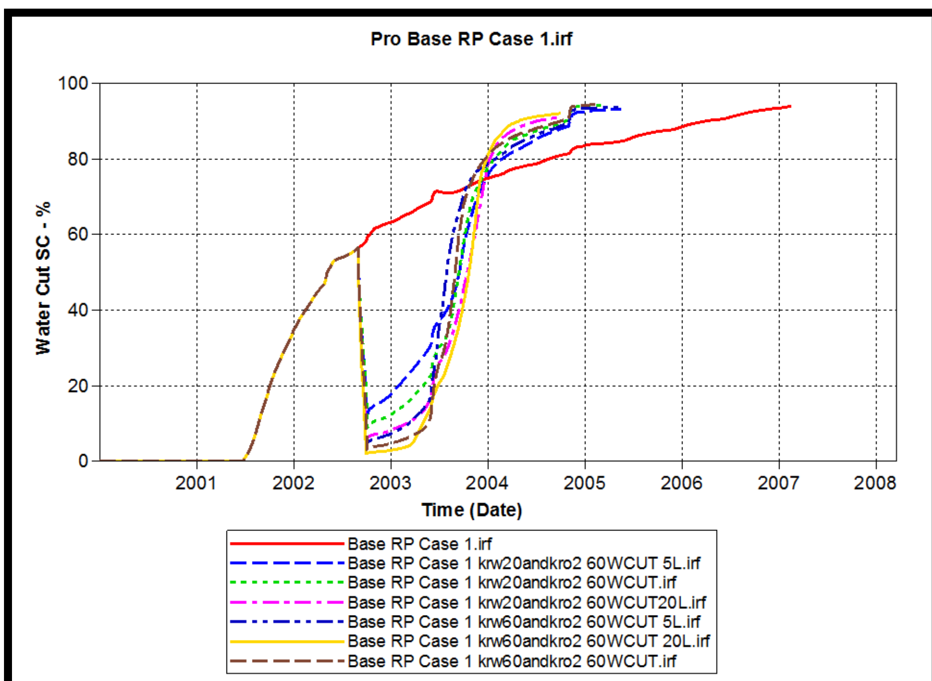


Figure 3.60 Water Cut Case 1.

Table 3.16 Impact of Gel Treatment Volume/Radius Effect on Accumulative Production and Oil Recovery Case1.

| RPM | RPM Radius (ft) | Volume of RPM ($ft^3$) | DATE | Cumulative Oil (STB) | Oil Recovery Factor (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|
| Base case 1 | | | 2/15/2007 | 172281 | 72.9948 | |
| krw/20,kro/2 60% WCUT | 28.21 | 125 | 5/16/2005 | 172171 | 72.6717 | 6.4 |
| krw/20,kro/2 60% WCUT | 39.9 | 250 | 3/6/2005 | 172267 | 72.7121 | 7.8 |
| krw/20,kro/2 60% WCUT | 56.43 | 500 | 1/10/2004 | 172259 | 72.7085 | 11.13 |
| krw/60,kro/2 60% WCUT | 28.21 | 125 | 5/17/2005 | 172388 | 72.7632 | 6.59 |
| krw/60,kro/2 60% WCUT | 39.9 | 250 | 2/8/2005 | 172292 | 72.7224 | 8.4 |
| krw/60,kro/2 60% WCUT | 56.43 | 500 | 1/10/2004 | 172699 | 72.8944 | 11.42 |

Table 3.17 Impact of Gel Treatment Volume/Radius on Effective Period (days) Case 1.

| RPM | RPM Radius (ft) | Volume of RPM ($ft^3$) | Effective period (day) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/20,kro/2 60% WCUT | 28.21 | 125 | 419 | 23224 | 41272 | 18048 | 7.6 |
| krw/20,kro/2 60% WCUT | 39.9 | 250 | 428 | 23169 | 43698 | 20529 | 8.7 |
| krw/20,kro/2 60% WCUT | 56.43 | 500 | 461 | 25110 | 49014 | 23904 | 10.1 |
| krw/60,kro/2 60% WCUT | 28.21 | 125 | 354 | 20245 | 39583 | 19338 | 8.2 |
| krw/60,kro/2 60% WCUT | 39.9 | 250 | 376 | 21148 | 43093 | 21945 | 9.3 |
| krw/60,kro/2 60% WCUT | 56.43 | 500 | 445 | 24355 | 49693 | 25338 | 10.7 |

Table 3.18 Impact of Gel Treatment Volume/Radius Effect on Accumulative Production and Oil Recovery Case 2.

| RPM | RPM Radius (ft) | Volume of RPM ($ft^3$) | DATE | Cumulative Oil (STB) | Oil Recovery Factor (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|
| Base case 2 | | | 5/16/2011 | 167639 | 70.763 | |
| krw/20,kro/2 60% WCUT | 6.3 | 5 | 8/1/2006 | 170963 | 72.166 | 22.9 |
| krw/20,kro/2 60% WCUT | 12.6 | 20 | 2/1/2006 | 170909 | 72.1431 | 26.9 |
| krw/20,kro/2 60% WCUT | 25.2 | 80 | 1/9/2005 | 170699 | 72.0544 | 31.01 |
| krw/60,kro/2 60% WCUT | 6.3 | 5 | 1/1/2006 | 170739 | 72.0714 | 27.59 |
| krw/60,kro/2 60% WCUT | 12.6 | 20 | 10/1/2005 | 170694 | 72.0524 | 30.2 |
| krw/60,kro/2 60% WCUT | 25.2 | 80 | 1/6/2005 | 170517 | 71.9776 | 33.21 |

Table 3.19 Impact of Gel Treatment Volume/Radius on Effective Period (days) Case 2.

| RPM | RPM Radius (ft)) | Volume of RPM (ft³) | Effective period (day) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/20,kro/2 60% WCUT | 6.3 | 5 | 1079 | 50296 | 90282 | 39986 | 16.9 |
| krw/20,kro/2 60% WCUT | 12.6 | 20 | 976 | 46524 | 92427 | 45903 | 19.4 |
| krw/20,kro/2 60% WCUT | 25.2 | 80 | 957 | 45705 | 95249 | 49544 | 20.9 |
| krw/60,kro/2 60% WCUT | 6.3 | 5 | 957 | 45705 | 92051 | 46346 | 19.6 |
| krw/60,kro/2 60% WCUT | 12.6 | 20 | 837 | 41545 | 90513 | 48968 | 20.7 |
| krw/60,kro/2 60% WCUT | 25.2 | 80 | 805 | 40195 | 92174 | 51979 | 21.9 |

Table 3.20 Impact of Gel Treatment Volume/Radius Effect on Accumulative Production and Oil Recovery Case 3.

| RPM | RPM Radius (ft) | Volume of RPM (ft³) | DATE | Cumulative Oil (STB) | Oil Recovery Factor (%) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|
| Base case 3 | | | 10/20/2010 | 166315 | 70.1998 | |
| krw/20,kro/2 60% WCUT | 28.2, 39.9 | 187.5 | 7/1/2006 | 171263 | 72.2881 | 21.20 |
| krw/20,kro/2 60% WCUT | 39.9, 56.4 | 375 | 2/6/2006 | 172183 | 72.6768 | 24.51 |
| krw/20,kro/2 60% WCUT | 56.4, 79.8 | 750 | 1/4/2005 | 172918 | 72.987 | 31.97 |
| krw/60,kro/2 60% WCUT | 28.2, 39.9 | 157.5 | 4/24/2006 | 171152 | 72.2415 | 22.45 |
| krw/60,kro/2 60% WCUT | 39.9, 56.4 | 375 | 2/1/2006 | 172210 | 72.7825 | 26.40 |
| krw/60,kro/2 60% WCUT | 56.4, 79.8 | 750 | 1/4/2005 | 173044 | 73.0401 | 32.07 |

Table 3.21 Impact of Gel Treatment Volume/Radius on Effective Period (days) Case 3.

| RPM | RPM Radius (ft)) | Volume of RPM (ft³) | Effective period (day) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/20,kro/2 60% WCUT | 28.2, 39.9 | 187.5 | 972 | 39820 | 74608 | 34788 | 14.7 |
| krw/20,kro/2 60% WCUT | 39.9, 56.4 | 375 | 952 | 39278 | 59819 | 20541 | 8.7 |
| krw/20,kro/2 60% WCUT | 56.4, 79.8 | 750 | 770 | 34471 | 81286 | 46815 | 19.8 |
| krw/60,kro/2 60% WCUT | 28.2, 39.9 | 157.5 | 956 | 39388 | 75541 | 36153 | 15.3 |
| krw/60,kro/2 60% WCUT | 39.9, 56.4 | 375 | 951 | 39236 | 62519 | 23283 | 9.8 |
| krw/60,kro/2 60% WCUT | 56.4, 79.8 | 750 | 717 | 32838 | 80269 | 47431 | 20.0 |

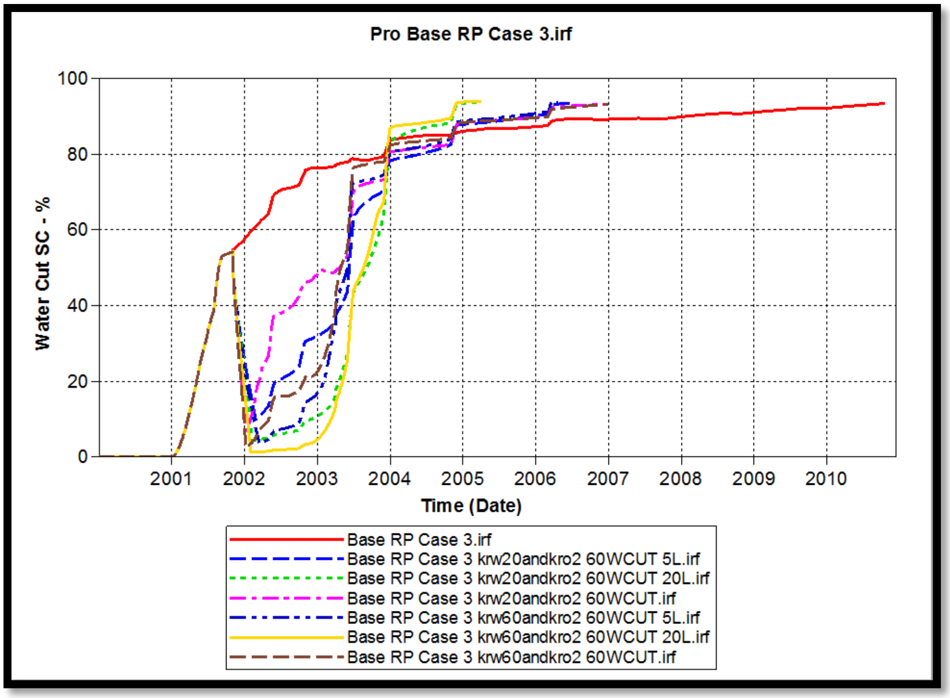


Figure 3.61 Water Cut Case 3.

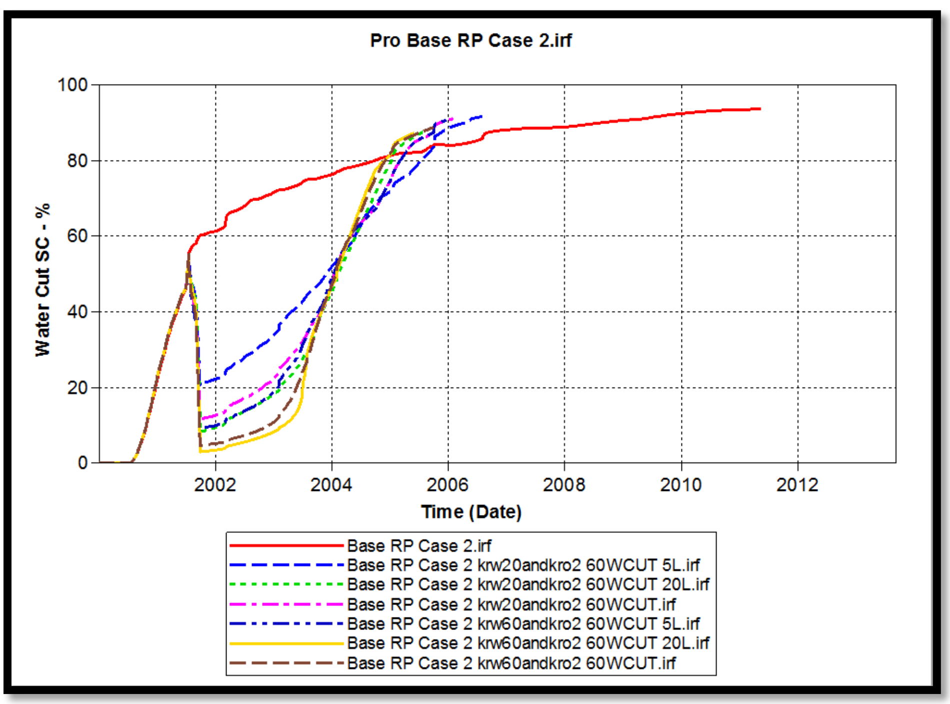


Figure 3.62 Water Cut Case 2.

Table 3.22 Impact of Gel Treatment Volume/Radius Effect on Accumulative Production and Oil Recovery Case 4.

| RPM | RPM Radius (ft) | Volume of RPM ($ft^3$) | DATE | Cumulative Oil (STB) | Oil Recovery Factor (%) | Oil Recovery (%) |
|---|---|---|---|---|---|---|
| Base case 4 | | | 1/16/2009 | 119431 | 50.4136 | |
| krw/20,kro/2 60% WCUT | 6.3, 12.6 | 12.5 | 10/1/2005 | 169304 | 71.4655 | 21.0519 |
| krw/20,kro/2 60% WCUT | 12.6, 25.2 | 50 | 10/1/2005 | 169304 | 71.4655 | 21.0519 |
| krw/20,kro/2 60% WCUT | 25.2, 50.4 | 200 | 1/5/2005 | 169241 | 71.4391 | 21.0255 |
| krw/60,kro/2 60% WCUT | 6.3, 12.6 | 12.5 | 7/1/2005 | 169960 | 71.7424 | 21.3288 |
| krw/60,kro/2 60% WCUT | 12.6, 25.2 | 50 | 7/1/2005 | 169960 | 71.7424 | 21.3288 |
| krw/60,kro/2 60% WCUT | 25.2, 50.4 | 200 | 1/19/2005 | 169571 | 71.5784 | 21.1648 |

Table 3.23 Impact of Gel Treatment Volume/Radius on Effective Period (days) Case 4.

| RPM | RPM Radius (ft)) | Volume of RPM ($ft^3$) | Effective period (day) | Total Oil production at Base Case (STB) | Total Oil production at RPM (STB) | Total Oil production Improvement (STB) | Oil Recovery Improvement (%) |
|---|---|---|---|---|---|---|---|
| krw/20,kro/2 60% WCUT | 6.3, 12.6 | 12.5 | 1406 | 45748 | 116702 | 70954 | 29.9 |
| krw/20,kro/2 60% WCUT | 12.6, 25.2 | 50 | 1406 | 45748 | 116702 | 70954 | 29.9 |
| krw/20,kro/2 60% WCUT | 25.2, 50.4 | 200 | 1376 | 45070 | 118773 | 73703 | 31.1 |
| krw/60,kro/2 60% WCUT | 6.3, 12.6 | 12.5 | 1360 | 44813 | 118645 | 73832 | 31.2 |
| krw/60,kro/2 60% WCUT | 12.6, 25.2 | 50 | 1361 | 44878 | 118709 | 73832 | 31.2 |
| krw/60,kro/2 60% WCUT | 25.2, 50.4 | 200 | 1192 | 42119 | 117904 | 75785 | 32.0 |

Table 3.24 Effect of Gel Treatment on Water Saturation.

| Case | Cumulative Water Injection (MSTB) | Cumulative Water Production (MSTB) |
|---|---|---|
| Base Case 1 | 520.47 | 269.62 |
| Case 1 with RPM | 347.00 | 95.033 |
| Base Case 2 | 830.70 | 587.82 |
| Case 2 with RPM | 395.60 | 147.88 |
| Base Case 3 | 789.07 | 548.37 |
| Case 3 with RPM | 383.40 | 131.02 |
| Base Case 4 | 660.70 | 491.12 |
| Case 4 with RPM | 369.00 | 122.87 |

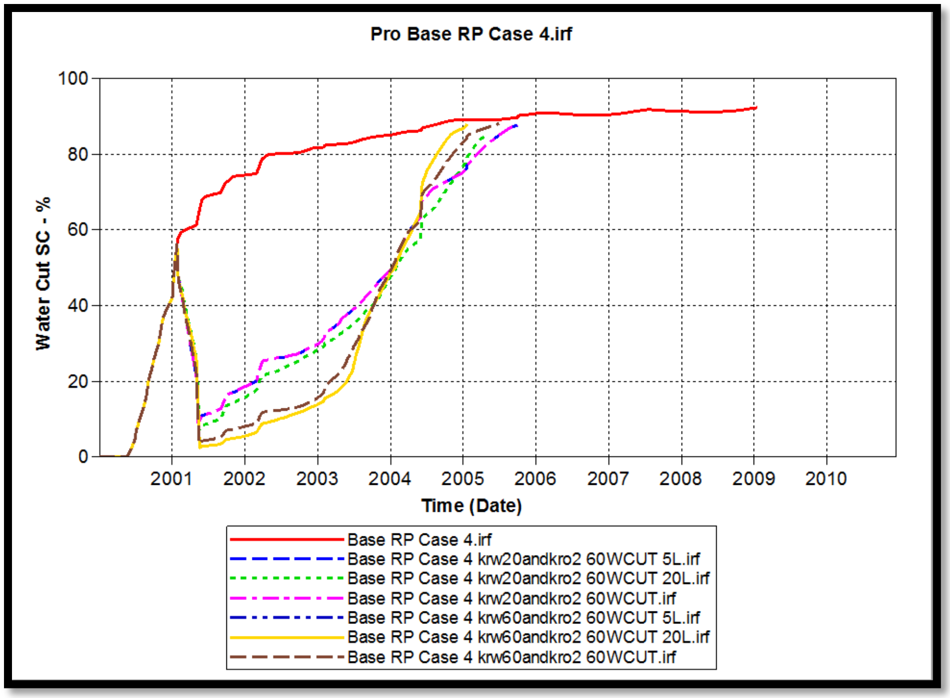


Figure 3.63 Water Cut Case 4.

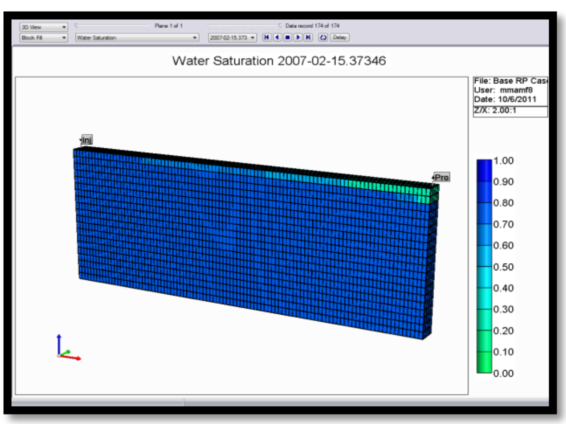


Figure 3.64 Water Saturation Base Case 1.

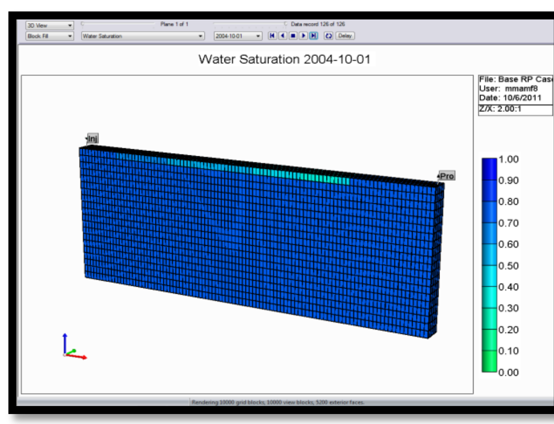


Figure 3.65 Water Saturation Case 1 After Effective Treatment.

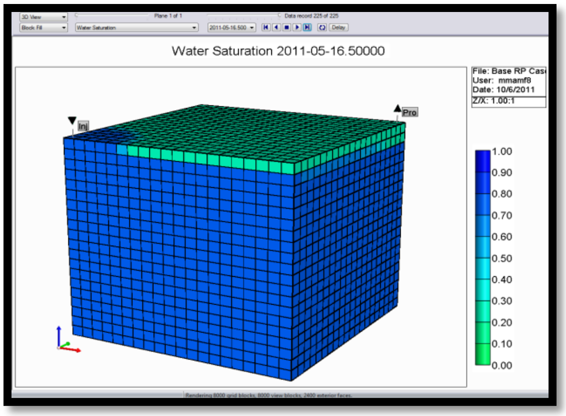


Figure 3.66 Water Saturation Base Case 2.

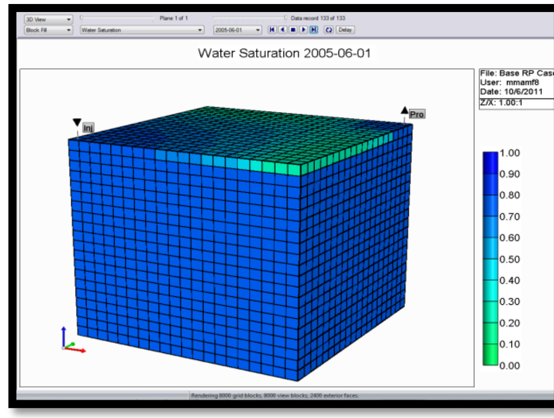


Figure 3.67 Water Saturation Case 2 After Effective Treatment.

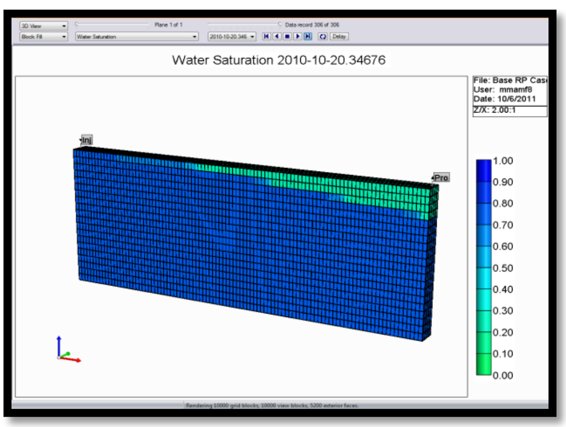


Figure 3.68 Water Saturation Base Case 3.

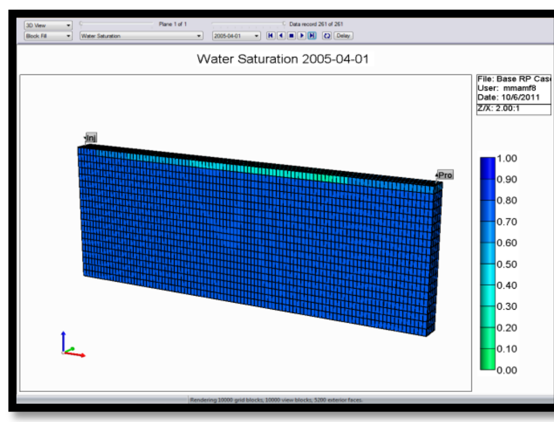


Figure 3.69 Water Saturation Case 3 After Effective Treatment.

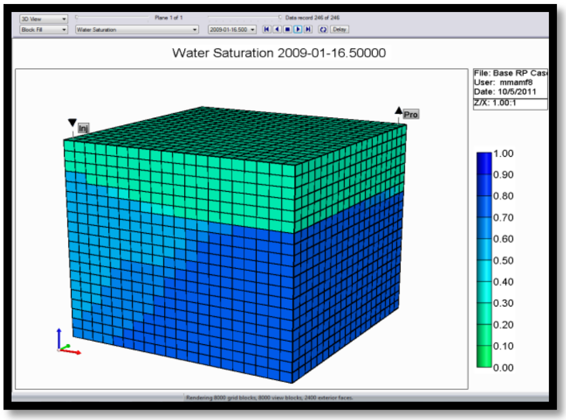


Figure 3.70 Water Saturation Base Case 4.

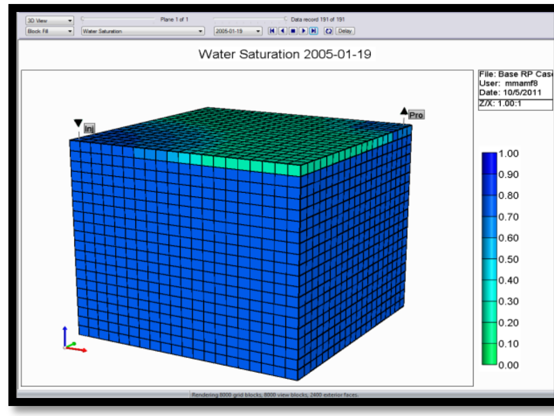


Figure 3.71 Water Saturation Case 4 After Effective Treatment.

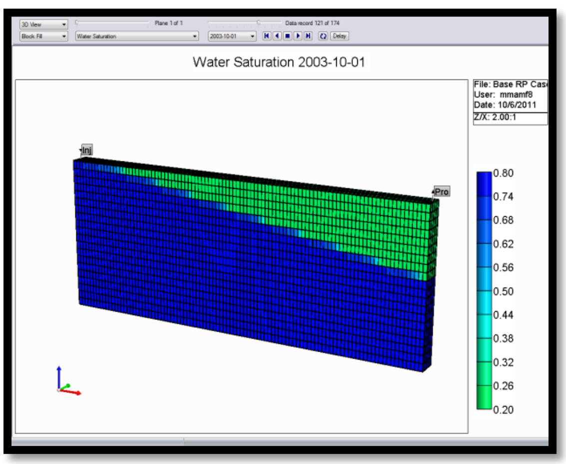


Figure 3.72 Water Saturation Base Case 1.

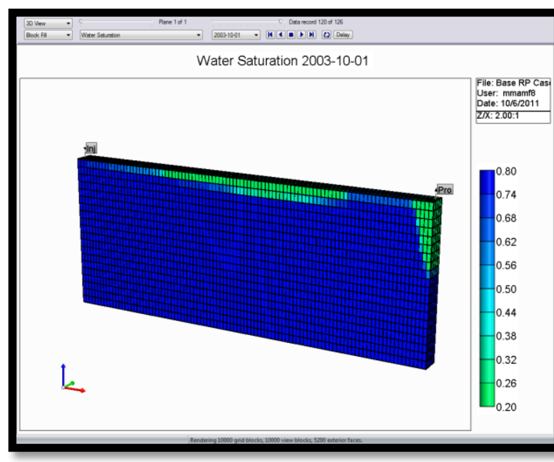


Figure 3.73 Water Saturation Case 1 with RPM.

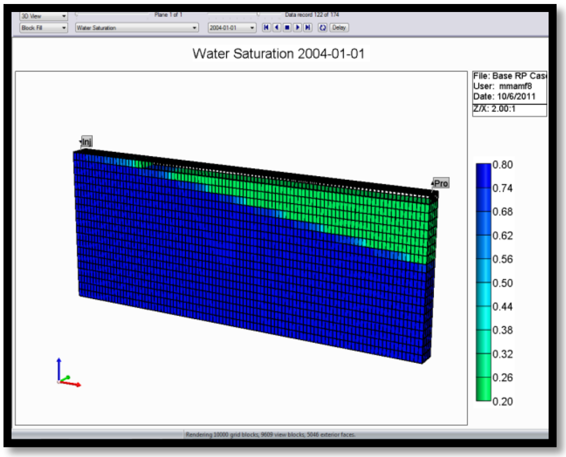


Figure 3.74 Water Saturation Base Case 1.

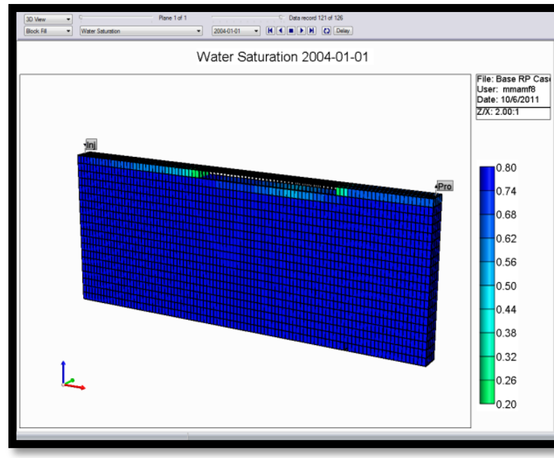


Figure 3.75 Water Saturation Case 1 with RPM.

# 4. CONCLUSIONS AND RECOMMENDATIONS

## 4.1 CONCLUSIONS

Numerical simulation was run investigate whether RPM can be used to reduce water production and increase oil recovery for two reservoir models: one lay homogeneous formation, the two-layer heterogeneous formation with crossflow. Linear flow and five-spot well patterns were considered for the simulation. The following the relative permeability modification with five spot and two layers flow pattern is more effective than linear flow with two layers and one layer. Conclusions are as follows:

- The effective period of DPR treatment is longer if treated in low water cut than in high water cut.
- DPR can improve oil production and reduce water production during the effective period of a treatment but the final recovery could not be significantly improved even sometimes worse.
- Better water control results can be achieved with more gel injection.

## 4.2 LIMITATION OF THE STUDY

- This study did not consider the potential damage of gel treatment on productivity.
- It is an ideal model of RPM treatment.
- The result is only used to give a general instruction about when and where RPM can be used further study should be implemented.

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# VITA

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